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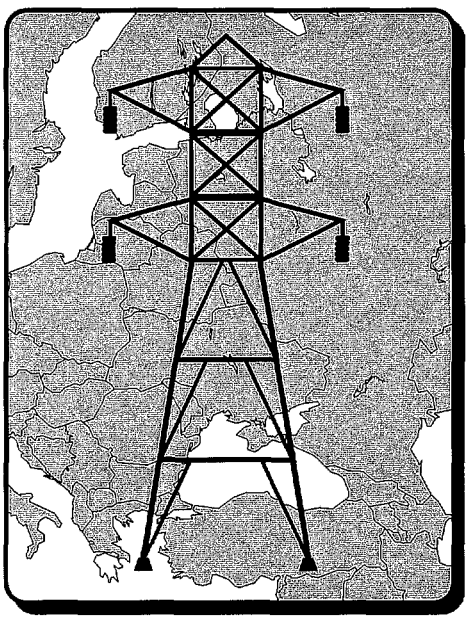
# Central and Eastern Europe Regional Energy Efficiency Project EUR-0030-C-00-2053-00



## Energy Pricing, Energy Efficiency, and Energy Sector Restructuring Component

Final Report
December 1996

**Volume VIII**

Prepared for:
U.S. Agency for International Development
Bureau for Europe and NIS
Office of Environment, Energy, and Urban Development
Energy and Infrastructure Division

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# CENTRAL AND EASTERN EUROPE
# REGIONAL ENERGY EFFICIENCY PROJECT
# EUR-0030-C-00-2053-00

**Energy Pricing, Energy Efficiency, and**
**Energy Sector Restructuring Component**

**Poland**
**Private Power legal Assistance**

*Task Completion Memorandum*

*Prepared for:*

U.S. Agency for International Development
Bureau for Europe and NIS
Office of Environment, Energy,
and Urban Development
Energy and Infrastructure Division

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TO: Robert Archer

DATE: May 31, 1994

FILE NO: 021280-0001

FROM: John Sachs

COPIES TO: David Keith

SUBJECT: Task Completion Memorandum: Task Order No. 1 - Poland Private Power Technical Assistance

## I. Introduction

In 1991, the Government of Poland began to implement a program to encourage private investment in the power sector. Several generating companies had already been transformed into joint stock companies, and they began to negotiate with foreign companies that proposed to form joint ventures with the joint stock companies and invest in the rehabilitation of their plants. The joint stock companies were asked to contribute the value of their plants, and the foreign investors promised to raise new capital on a project finance basis.

In order to complete a project financing, it was essential that the joint venture secure a source of long-term revenue from the sale of power (and steam, if any) in contracts. Therefore, Latham & Watkins was asked by U.S. AID to assist the Polish Power Grid Company ("PSE-SA") in the development of model power delivery agreements to govern the purchase of electricity from the joint ventures. In fact, we were asked to develop separate forms for power-only and for combined heat and power plants. In addition, we were requested to assist PSE-SA in the negotiation of several of these agreements with five different joint ventures that were pursuing the rehabilitation of existing power plants in Poland.

Simultaneously, we were asked to represent MPEC, the district heating company in Krakow, in its negotiations with the Krakow-Leg joint venture. Finally, we were asked to advise various ministries of the Government with respect to additional support, including guaranties, that the foreign investors requested.



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## II. Objectives

Task Order No. 1 was intended to further the following objectives:

- creating a legal and contractual environment in Poland which is conducive to the development of private power projects;
- teaching PSE-SA the basic concepts of project finance and private power;
- assisting PSE-SA and other governmental entities in the negotiation of the first private power agreements; and
- training PSE-SA personnel in negotiation skills.

## III. Work Performed

### A. Organization of Work and Personnel

Latham & Watkins was asked to assemble a small team of project finance lawyers to accomplish the above objectives. The principal members of the team were John Sachs, Dennis Nordstrom and Paul Hunt. John Sachs served as team leader.

With respect to the work with PSE-SA, the Latham team was paired with the two departments of PSE-SA that were handling negotiations with private developers: the International Strategy Division and the Economic Division. More specifically, Latham lawyers were paired with Zygmunt Iwanejko and Jacek Brandt. Polish legal advice was provided by PSE-SA's in-house counsel, Hanna Napierala. We also coordinated with Carlos Yermoli of RCG/Hagler Bailly on pricing issues.

With respect to our work with other governmental agencies, we were paired with Mr. Freisler of MPEC, Mr. Luczkiewicz of the Ministry of Industry and Trade, and Mr. Kalicki of the Ministry of Finance.

### B. Schedule and Activities

The work under Task Order No. 1 was basically organized in three phases. The first phase commenced in September 1991 and concluded in June 1992. It entailed the preparation of a model power delivery agreement which was consistent with the objectives of PSE-SA, the fundamentals of project finance and the requirements of Polish law. Approximately five trips to Poland were required to accomplish this phase.

Phase 2 commenced in October 1992 and continued until June 1994. This phase focused on the negotiation of power



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delivery agreements between PSE-SA and the different joint ventures formed by United Energy Partners (U.S.), Vattenfall (Sweden), Coastal Power Production (U.S.), AES/Transpower (U.S.) and Infrastructure Services Inc. (U.S.) to pursue the rehabilitation of the Krakow-Leg, Patnow, Gorzow, Chorzow and Lublin Projects, respectively. We travelled to Poland approximately seventeen times during this period to accomplish the work under this phase.

Commencing in January 1993, the third phase overlapped the second phase somewhat. The purpose of this phase was to advance the negotiations of the various joint ventures with governmental agencies other than PSE-SA. To that end, a series of meetings were held with the Ministry of Industry and Trade and the Ministry of Finance beginning in January 1993 with respect to guarantees and other forms of governmental support. Starting in April 1993, we also began to assist MPEC in the negotiation of a steam sales agreement with the Krakow-Leg joint venture. These meetings were generally scheduled at the same time as the meetings with PSE-SA for Phase 2 purposes.

## IV. Results

Phase 1 produced both tangible and intangible results. First, we produced a model power delivery agreement which became the starting point for negotiations with each of the joint ventures. This model agreement was delivered to U.S. AID in 1992, but it was subsequently modified and replaced with new model agreements. Second, we succeeded in educating PSE-SA personnel with respect to private power issues and the contractual provisions that will be required.

The results of Phase 2 consist of five power delivery agreements in differing stages of negotiation. The power delivery agreement for the Krakow-Leg was perhaps the furthest along until the Ministry of Privatization suspended the negotiations concerning the Krakow-Leg project. Since that time, the negotiations surrounding the Patnow project have overtaken and surpassed the Krakow-Leg project. Next most developed was the power delivery agreement for the Gorzow project, but this joint venture and the joint venture pursuing the Lublin project both withdrew during the last six months. Finally, the AES/Transpower team suspended negotiations after our initial meetings pending review of the price PSE-SA was offering to pay. Although these various power delivery agreements are still in a state of flux, we captured the essence of these agreements - the common threads - in new model agreements about six months ago. (See Attachments A and B). In addition, through these negotiations, we were able to train PSE-SA in negotiation skills.

Finally, as a result of Phase 3, we made significant progress in the negotiation of a steam sales agreement between

MPEC and the joint venture pursing the Krakow-Leg project until the Ministry of Privatization interceded. We also advised the Ministry of Industry and Trade and the Ministry of Finance on the need other forms of support required by private power projects. Three memoranda on government guarantees and other implementation agreement issues were produced. (See Attachments C through E).

## V. Lessons Learned

### A. Political Will

Perhaps the single biggest problem confronting private power in Poland is the absence of a coherent Government policy in favor of private power. The absence of such a policy is predictable given the current oversupply of capacity and the many competing demands for Government attention and money. Nevertheless, without such a policy (and the corresponding support), the private sponsors have found it impossible to resolve the political issues and even some of the commercial issues. The Government, for example, has offered no assistance with respect to the many permits and approvals required for a private power project, and the Government has not addressed the questions concerning the availability of foreign exchange. Moreover, the Government has not offered any guidance (such as an assurance of a pass-through in PSE-SA's rates) much less financial support (such as direct payments from the Government) with respect to political force majeure events. Finally, the Government has declined to offer guarantees of the performance (or even the payment obligations) of PSE-SA. In our view, most private power projects in Poland will not succeed until the Government establishes a coherent policy that addresses these issues.

### B. Privatization Process

The current state of indecision within the Government as to the wisdom of, and method for, privatization has also created a major obstacle for private power. After permitting the U.S. partner in the Krakow-Leg project to pursue a joint venture privatization for three years, the Government recently decided to wrest the project from the hands of the U.S. partner and to hold a competition for a capital privatization (which another company won). The Government (and perhaps some of winning bidders) have not only disregarded the likely impact of this decision on the power purchase price that will be required to support a project financing of this project, but the Government has also overlooked the likely chilling effect of this decision on the enthusiasm of private sponsors for other private power projects. Here too, a coherent Government policy which establishes a procedure for privatization of power generation would be helpful.

C. Restructuring and Regulation

Similarly, the on-going restructuring of the power sector and the possibility of further changes in the regulatory environment have also created impediments to the development of private power. The Government naturally sought to avoid undertaking obligations in the various agreements that may be inconsistent with the subsequently imposed rules, and the joint ventures could not assess the risks which they confronted. For example, there was a concern that more stringent environmental laws may be enacted in the future. Because compliance with these laws could be costly, the joint ventures asked for protection against such increased costs. The Government, however, did not know if these laws would be applied retroactively, and, if they were, it was unclear which governmental agency should offer protection. Such problems can be minimized if restructuring is completed and a stable regulatory environment is established in advance.

D. Pricing

On a more concrete level, the uncertainty of the future pricing arrangements throughout the power sector has complicated the process and delayed the development of private power. PSE-SA, for example, did not wish to agree to a wholesale power purchase price which was higher than that it could collect from the sale of power to the distribution companies. For their part, the joint ventures did not wish to invest time and money in the negotiation of "non-price" terms in the power purchase agreement until the purchase price was known. Moreover, the joint ventures could not negotiate the price of steam sales until they knew what they would be paid for power. Ideally, all of these pricing arrangements would have been established and stabilized before initiating discussions with the joint ventures.

E. Organization

Despite our efforts to define PSE-SA's internal position in advance of the negotiations with the joint ventures, it will nevertheless have taken over three years to conclude the first private power contract. This time period could have been shortened with improved internal organization and coordination. If the Government had convened an inter-ministerial committee before the commencement of negotiations to decide upon such major issues as the availability of Government guaranties and the protection to be afforded against cost increases caused by changes in environmental regulation, it might have saved time. Similarly, it would have been more efficient if multiple documents - such as the power sales contract, the steam



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sales contract and the implementation agreement - had been negotiated in parallel rather than in sequence.

F. Complete Advice

Finally, our experience in Poland has demonstrated the importance of assembling a broad range of talents early in the development of a private power project. Both the joint ventures and the relevant Government agencies (including the ministries, the generators, the transmission company and the district heating companies) would have been wise to retain engineering, financial, legal and insurance experts - all with experience in international project finance - early in the process. With such advice, both sides would have had the confidence to make decisions and agree on terms more quickly.



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# Poland Private Power Technical Assistance

**Objectives**

1. create a legal and contractual environment in Poland which is conducive to the development of private power projects;

2. teach PSE-SA the basic concepts of project finance and private power;

3. assist PSE-SA and other governmental entities in the negotiation of the first private power agreements; and

4. train PSE-SA personnel in negotiation skills.

# Poland Private Power Technical Assistance

## Task Description

### Phase 1

Prepare a model power delivery agreement which was consistent with the objectives of PSE-SA, the fundamentals of project finance and the requirements of Polish law.

### Phase 2

Negotiate power delivery agreements between PSE-SA and five different joint ventures pursuing the rehabilitation of the existing power plants.

### Phase 3

Advance the negotiations of the various joint ventures with other governmental agencies, including the Ministry of Industry and Trade, the Ministry of Finance, and district heating companies.

# Poland Private Power Technical Assistance

## Results

### Phase 1

Produced model power delivery agreements which were and will be used as the starting point for future negotiations with joint ventures.

Educated PSE-SA personnel with respect to private power issues and contracts.

### Phase 2

Negotiated power delivery agreements with five different joint ventures.

Trained PSE-SA personnel in negotiation skills.

### Phase 3

Negotiated one steam sales agreement between the district heating company in Krakow.

Advised the Ministry of Industry and Trade and the Ministry of Finance on the need other forms of support required by private power projects.

# Poland Private Power Technical Assistance

**Lessons Learned**

1. The Government should establish a coherent policy in favor of private power earlier in the process.

2. The Government should establish the methodology for privatization of power generation in advance.

3. The planned restructuring and new regulatory framework should also be established in advance.

4. The utility should determine the power purchase price before initiating discussions with private sponsors.

5. Meetings of all relevant governmental agencies should be convened early in the process to coordinate the substantive positions of such agencies and the negotiation of their respective agreements (if any) with the private sponsors.

6. Both sides should assemble a broad range of talents - including engineering, financial, legal and insurance experts with experience in international project finance - early in the development of the project.

# CENTRAL AND EASTERN EUROPE
# REGIONAL ENERGY EFFICIENCY PROJECT
# EUR-0030-C-00-2053-00

**Energy Pricing, Energy Efficiency, and Energy Sector Restructuring Component Poland - Support to Private Power and Tariff Reform**

*Task Completion Memorandum*

*Prepared for:*

U.S. Agency for International Development
Bureau for Europe and NIS
Office of Environment, Energy,
and Urban Development
Energy and Infrastructure Division

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# POLAND TASK #2
# SUPPORT TO PRIVATE POWER AND TARIFF REFORM

Task Completion Memorandum

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4. **Results and Lessons Learned**

# POLAND TASK #2

# SUPPORT TO PRIVATE POWER AND TARIFF REFORM

## 1. BACKGROUND

### The Power Sector in Poland

Poland has nearly 400 powerplants and combined heat and power stations with an installed capacity of 29,627 MW. Almost all of the country's electric energy is produced by lignite- and coal-fired power stations, many of which have severe environmental impacts. Lignite-fired plants produce the lowest-cost energy (if environmental costs are ignored), and contribute 43% of total production.

The facilities are currently operated by 32 generating companies, 23 combined-heat and power companies, a national transmission company (Polskei Sieci Elektroenergotyczne, or Polish Power Grid Company, PPGC) and 33 distribution companies. However, as part of the energy sector restructuring program, these entities are expected to be reorganized into a fewer number of generation and distribution companies.

Because of the recent fall in electric sales, new generation capacity is not immediately required. However, massive investments are necessary to reduce environmental emissions and improve efficiency to reasonable levels.

Over the past four years, the Government of Poland (GOP) has begun to introduce sweeping legal and regulatory reforms to accelerate the transition to a market-oriented economy. The GOP has recognized the key role of the energy sector in this fundamental transformation, both in terms of its importance to other sectors as well as its own investment needs. Consequently, the GOP initiated the Energy Sector Restructuring, Privatization, and Regulatory Reform Program. This program aims to liberalize energy prices, promote enterprise competition within the energy sector, and transform the ownership, control, and operation of state-owned enterprises in a manner consistent with a market model of the energy sector.

PPGC has already been reorganized as a joint stock company, currently owned by the National Treasury. It will retain its role as the single national transmission company. Currently it is also responsible for system planning, dispatch, and control, bulk power purchases and sales, and retail tariff recommendations.

It is expected that a regulatory agency will be established as part of an "energy law," which is currently under preparation. This agency will supervise the operation of the power market.

**Electricity Pricing Study**

A study of electricity tariffs and transfer prices in Poland has recently been conducted under the auspices of the EASTERN EUROPE REGIONAL ENERGY EFFICIENCY PROGRAM and resulted in recommendations for tariff levels over the medium term. This study will need frequent updating and refinement in order to keep pace with newly available data and developments regarding the modernization and restructuring of the Polish power sector.

**Independent Power Production**

Independent Power Production (IPP) usually relates to supply of electricity to the grid by facilities not under the ownership or direct control of the electric utility. In Poland, IPP would be developed by the private sector, and so IPP is a logical first step toward privatization of electricity services. Within the category of independent power there are a variety of facilities that may be constructed, including industrial cogeneration plants, district heating cogeneration (combined heat and power plants), small hydroelectric projects, renewable energy projects, and power plants that are designed exclusively to sell power to the grid. The acquisition of capacity and energy from IPPs is fully consistent with the least-cost Integrated Resource Plan approach.

**The Need for IPP in Poland**

Poland's power sector faces two key problems, which IPP can help address:

1. Lack of modern environmental emissions control technologies. Because environmental standards in the past were less stringent in Poland than in western Europe, the control technologies in place are less advanced. Although advanced research on environmental control technologies has been conducted in Poland, operating experience with control technologies for full-scale power plants is relatively limited. In this context private power may be viewed as one of the policy tools available to promote technology transfer from western countries.

2. A shortage of capital. The capital requirements for environmental controls at lignite and coal-fired plants are very large relative to the amount of capital available to the electric utility companies from public sector sources. Thus there is interest in the ability of IPP (including foreign private investment) to provide additional capital for power generation.

These factors create a favorable climate for private power, and IPP development. However, to attract the foreign investment required, the introduction of systems necessary for the preservation and enhancement of invested capital are critical. Poland has no electric utility regulatory agency

comparable to those in the U.S. or other western countries where IPP's now operate. Various agencies are charged with oversight of bulk power sales or electric tariffs, but have a shortage of staff available to perform regulatory functions.

## 2. OBJECTIVES

The activities under this tasks were in support of the general objective to create the conditions needed to facilitate the development of private power in Poland and in particular assistance to create the institutional, legal and regulatory framework and the financial institutions and accounting practices needed to provide opportunities for private power. A.I.D. assistance in this area includes support to MOIT's Energy Restructuring Group, the Electricity Tariff Study for PPGC and this task.

### Training in Pricing

Several computer models were prepared, calibrated and used during the electricity pricing study and PPGC received presentations and training sessions on the capabilities and operation of the models. However, for PPGC to make effective use of the models it needs extensive hands-on training, detailed documentation and descriptions on the use of the models for different planning applications, including the determination of system avoided costs.

### Assistance in IPP Price Determination

While the tariff study recommends the principle of avoided cost as a sound basis for economic and efficient allocation of power sector resources and it offers a general calculation of the avoided cost of the Polish system it does not lend itself directly to the determination of specific prices for private power because: 1) it does not elaborate on the details for the computation of avoided costs of specific resources, 2) it does not include the determination of an avoided cost of capital compatible with private sector ownership and 3) its practical application in a negotiation context demands simplification.

## 3. WORK PERFORMED

The work performed under this task can be best described in terms of three major components: 1) training and documentation , 2) development of a practical tool for evaluation of offers and 3) assistance in the evaluation and negotiation of power supply offers.

### Training and Documentation

Training and documentation focused on the following models:

**Generation Planning Tools (GPT) Model**

This is an advanced long term planning model capable of simulation and optimization of power generation systems. Hagler Bailly provided a one week training course to designated staff of PPGC including:

- Instructions and hands-on training on the modification of existing input files in light of new data.
- Use of the model GPT as a tool to assist in the comparison of alternative capacity expansion plans.
- Application of the above to the computation of avoided cost of specific resources and to the computation of marginal cost of capacity.

**GPT-L and GPT-M Models**

These are two auxiliary models of GPT used in the short term hourly analysis of reliability and marginal cost of the system. Hagler Bailly provided training on these models to designated staff of PPGC covering the following aspects:

- Modifications of the existing input file of the model GPT-L in light of more recent historical load data.
- Use of the model GPT-L to develop input data to the models GPT and GPT-M.
- Modifications of the input file of model GPT-M with new data generated by the models GPT-L and GPT.
- Use of the model GPT-M to develop the hourly reliability and marginal generation cost of the system for a target year of tariff design.

Detailed documentation on each of these models was submitted to PPGC including description of the logic, definition of each input value and recommendations for data preparation.

**Development of a Simplified Tool for Avoided Cost Determination**

The GPT model described above is the ideal tool for detailed computation of the avoided cost of a specific resource to the system and therefore an excellent tool for determining the fair value of power offered by the private sector. However, the interpretation of results of any detailed generation planning model is generally at a technical level different from that of the people involved in negotiating power transactions and therefore a simplified formulation is desirable.

To meet this need a simplified spreadsheet was prepared and calibrated with the results of the GPT model making it possible for PPGC to compute, as a single parameter, the value of any offer for private power and to assess the impact of different assumptions and cost components upon that value. Furthermore, the parameter chosen to measure value was the equivalent opportunity cost of capital to PPGC from the private sector thereby eliminating any arbitrary selection of discount rate in the evaluation of offers and providing PPGC a realistic perception of investor expected returns.

**Assistance in the Evaluation of Power Supply Offers**

Using the simplified model described above these offers were analyzed and ranked in order of priority for negotiation. PPGC received offers from the private sector for power supply from combined heat and power (CHP) plants

PPGC concluded a contract with the plant recommended as first priority.

## 4. RESULTS AND LESSONS LEARNED

**Results**

The following results were obtained from the activity:

- Proficiency at PPGC in the use of a detailed planning model compatible with its pricing policies.
- Availability at PPGC of a simplified evaluation tool compatible with the detailed planning and pricing model and providing a fair reference for evaluation of power purchase offers.
- Agreement between PPGC and a combined heat and power plant subject of private investment in rehabilitation.

Some of the expected results were not entirely achieved for reasons described below.

**Training in Tariff Design**

While PPGC is proficient in the use of the models, it lacks full confidence in determining future marginal cost tariffs has not been achieved. At the time the tariff study was done several key inputs were not available and the system was operating in an abnormal way forcing a number of assumptions and deviations from formal procedures that introduced a higher component of judgement than is normally necessary and preventing the definition of a clear cut and replicable procedure in some of the many steps involved.

As other studies are being completed yielding firm data and the system adopts more conventional characteristics most of these problems will be resolved.

**Assistance in Private Power Pricing**

Only one of the offers received by PPGC concluded in a signed agreement within the duration of the assistance. While this reflects a measure of success it remains less than expected.

One of the reasons is that the system currently exhibits a low value of avoided costs relative to other markets thus reducing interest by investors. However, a more important aspect could be the absence of an independent regulatory authority and uncertainties about the GOP policy for the power sector which dampened the climate for enthusiastic negotiation on both sides.

**Lessons Learned**

Poland is making progress towards a market oriented power sector and A.I.D. assistance has contributed significantly to this end. However, progress has been slower than could be anticipated largely due to a readjustment of policies towards a more gradual transformation of the power industry. Evidence of this can be found as follows: 1) Electricity tariffs, when measured in US currency appear to follow closely the recommendations of the A.I.D. funded study however a growing gap between local inflation and currency devaluation may indicate a much slower progress. 2) Disaggregation of the generation system continues to be an objective but has been transformed to only partial disaggregation over the medium term.

This change in the pace of transformation does not lessen the urgency to create conditions for the development of private power since environmental targets remain ambitious and the needs for efficiency improvements continues to exist, but it does limit the enthusiasm of the private sector and frustrates the efforts of those in the public sector responsible for attracting that much needed investment.

In this context A.I.D. assistance could appear to be less than fully effective but it actually may be keeping a much needed momentum so that once the political brakes are released transformation can pick up speed fast.

PPGC staff are now familiar with modern principles of power pricing at both wholesale and retail level and they are in the process of updating the electricity tariffs based on those principles. Practical tools are available to determine fair prices for independent producers and there is at least one agreement for power deliveries based on avoided costs. These are important steps in the development of an active market for private investment in the power industry.

# ELECTRIC POWER TARIFF STUDY:
# POLISH POWER GRID COMPANY

Final Report

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# ELECTRIC POWER TARIFF STUDY:
# POLISH POWER GRID COMPANY

Final Report

*Prepared for:*

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# STRESZCZENIE

## S.1 WSTĘP

### Cele i podziękowania

Niniejsze studium zostało przeprowadzone w ramach Regionalnego Programu Wydajności Energii (180-0030) sponsorowanego przez Agencję Stanów Zjednoczonych ds. Rozwoju Międzynarodowego (United States Agency for International Development - A.I.D.). Jego celem była pomoc Rządowi Polski w opracowaniu detalicznych i hurtowych taryf na energię elektryczną w perspektywie średnioterminowej, spójnych z celami ekonomicznie sprawnego i samofinansujścego się systemu elektroenergetycznego.

RCG/Hagler Bailly pragnie wyrazić podziękowanie za współpracę i pomoc udzieloną przez wiele polskich i międzynarodowych organizacji w trakcie opracowywania studium, w szczególności Polskim Sieciom Elektroenergetycznym S.A., Agencji Stanów Zjednoczonych ds. Rozwoju Międzynarodowego oraz Bankowi Światowemu.

### Sposób podejścia do studium

Zaplanowano, że realizacja studium taryfowego będzie przebiegać w czterech głównych etapach:

- analiza prognozy obciążenia i planów inwestycyjnych
- opracowanie ekonomicznych kosztów krańcowych
- prognoza wymaganych przychodów finansowych
- opracowanie taryf na energię elektryczną o strukturze opartej na ekonomicznych kosztach krańcowych pozwalających na uzyskanie wymaganych przychodów finansowych.

# SUMMARY

## S.1 INTRODUCTION

### Objectives and Acknowledgements

This study was conducted under the auspices of the Regional Energy Efficiency Project (180-0030) of the United States Agency for International Development (A.I.D.). Its objective was to assist the Government of Poland in developing retail and bulk power tariffs for the medium term, compatible with the goals of an economically efficient and financially self-sustainable power system.

RCG/Hagler Bailly, Inc. wishes to acknowledge the assistance and cooperation received from many Polish and international organizations during the execution of the study, and in particular, the Polish Power Grid Company, A.I.D., and the World Bank.

### Approach to the Study

The tariff study was planned to proceed according to four major steps:

- review of load forecast and investment plans
- development of economic marginal costs
- forecast of financial revenue requirements
- development of electricity tariffs structured on the basis of economic marginal costs and designed to recover financial revenue requirements.

Studium zostało przeprowadzone w okresie od czerwca 1992 roku do lipca 1993 roku, w okresie, w którym nastąpiło wiele istotnych zmian w ogólnej strukturze sektora elektroenergetycznego, w programie inwestycji w rozwój i modernizację systemu oraz w przepisach regulacyjnych i podatkowych determinujących działanie systemu i wpływających na przepływy pieniężne w okresie średnioterminowym. W wyniku tak zmieniającego się środowiska oraz z racji nieuchronnie iteracyjnego charakteru analizy, studium przybrało formę procesu dwufazowego.

The study was conducted during the period June 1992 to July 1993 and in parallel with many important developments regarding the corporate structure of the power sector, the forecast of investments in the expansion and modernization of the system, and the regulatory and fiscal policies that would guide its operation and affect its cash flow over the medium term. As a result of this changing environment and of the inherently iterative nature of the analysis, the study can be best described as a two-stage process.

W fazie pierwszej, trwającej od czerwca 1992 roku do marca 1993 roku, przeprowadzono badanie ekonomicznej struktury kosztów i dokonano prognozy co do wymaganych przychodów dla systemu, przy założeniu, że nie będzie żadnych barier ograniczających możliwość przeszacowania majątku w sektorze elektroenergetycznym lub wprowadzenia podwyżek cen energii elektrycznej.

The first stage, carried out from June 1992 to March 1993, examined the economic structure of costs and projected the revenue requirements of the system assuming no external constraints on the feasibility of revaluating assets in the power sector or the feasibility of implementing tariff increases.

W fazie drugiej, przeprowadzonej w okresie od kwietnia do lipca 1993 roku, wykorzystano struktury ekonomiczne opracowane w fazie pierwszej. Dokonane w niej prognozy finansowe brały już jednak pod uwagę realny harmonogram przeszacowywania majątku i program stopniowych podwyżek cen energii elektrycznej przygotowany w celu zminimalizowania negatywnego wpływu społecznego i ekonomicznego.

The second stage, carried out from April to July 1993, made use of the economic structures developed in the first stage. However, its financial projections took into account a practical schedule for asset revaluations and a program of gradual tariff increases designed to minimize negative public and economic impact.

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## Organizacja raportu

Niniejsze studium składa się z czterech części. Pierwsza faza analizy została przedstawiona w trzech pierwszych częściach. Część I zawiera trzy rozdziały, w których omówiona została ogólna charakterystyka systemu i dokonany przegląd bilansu podaży i zapotrzebowania w Polsce. Część II zawiera analizę podsystemu wytwarzania, w której zastosowane zostały ścisłe kryteria efektywności finansowej i z której wyliczono hurtowe taryfy na zakup energii elektrycznej od wytwórców. W części III przedstawiona została ekonomiczna i finansowa analiza podsystemów przesyłu i rozdziału energii elektrycznej, w której nadal zachowane są ścisłe kryteria efektywności finansowej i której wynikiem są hurtowe taryfy na sprzedaż energii elektrycznej do zakładów energetycznych i wielkich odbiorców oraz średnie taryfy dla odbiorców detalicznych.

Część IV odpowiada ostatniej fazie analizy i obejmuje, po pierwsze, analizę wpływu wzrostu cen energii elektrycznej na polską gospodarkę. Po niej następują różne rodzaje finansowej analizy podsystemów wytwarzania, przesyłu i rozdziału energii elektrycznej w warunkach różnych scenariuszy ograniczeń narzuconych przez politykę podatkową oraz polityczną możliwość wprowadzenia podwyżek cen energii elektrycznej. Opracowanie kończy się szczegłowym przedstawieniem taryf w rozbiciu na poziomy napięć i kategorie odbiorców wyliczonych w oparciu o najbardziej prawdopodobny scenariusz przeciętnych wpływów pieniężnych wynikających z analizy finansowej uwzględniającej narzucone ograniczenia.

Schemat S-1 przedstawia najistotniejsze powiązania między różnymi rozdziałami raportu. Dla zachowania przejrzystości, w podsumowaniu tym nie zachowano dokładnej kolejności prezentacji materiału w tekście głównym, lecz jedynie zaznaczono, w których rozdziałach omawiany jest dany temat.

## Organization of the Report

This study has four parts. The first stage of the analysis is covered by the first three parts of the study. Part I contains three chapters describing the general characteristics of the system and presents a review of Poland's supply and demand balance. Part II contains the analysis of the generation system, applying strict financial performance criteria and resulting in bulk purchase tariffs to generators. Part III carries the economic and financial analysis through the transmission and distribution components, maintaining strict financial performance criteria and resulting in bulk sales tariffs to distribution companies and large consumers and average retail tariffs.

The second stage is covered in Part IV. It first incorporates an analysis of the impact of tariff increases on the Polish economy. This is followed by different cases of financial analysis of the generation, transmission and distribution components as affected by different scenarios of constraints regarding fiscal policy and the political feasibility of tariff increases. Finally, a detailed tariff design with disaggregation by voltage level and customer class is presented on the basis of the most likely scenario of average revenues determined through the constrained financial analysis.

Exhibit S-1 shows the flow and main linkages among different chapters of the report. For the sake of clarity, this summary does not strictly follow the order of the main text, but the chapters where a specific subject is treated are denoted.

SCHEMAT S-1

# "Mapa Drogowa" do Studium

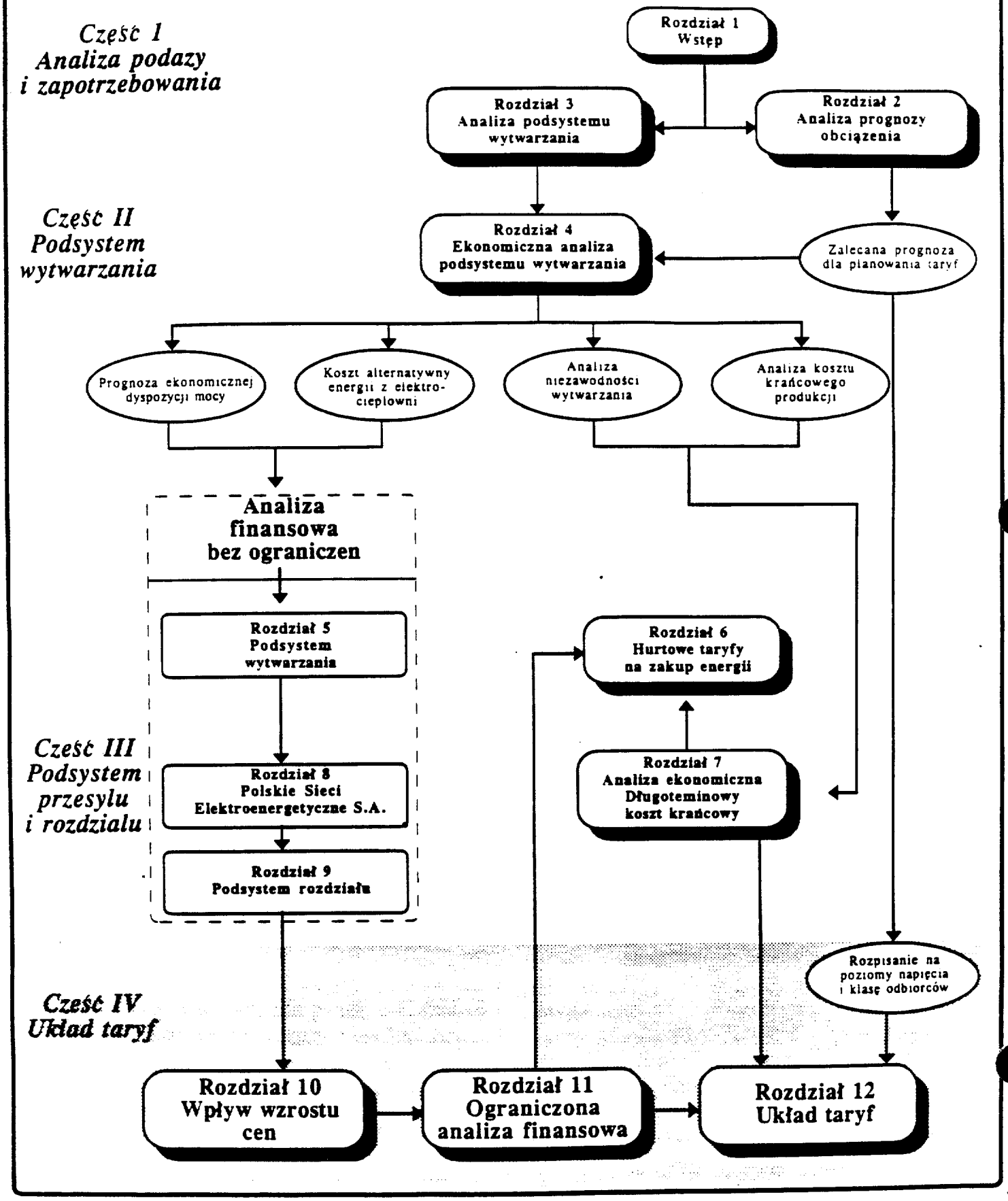
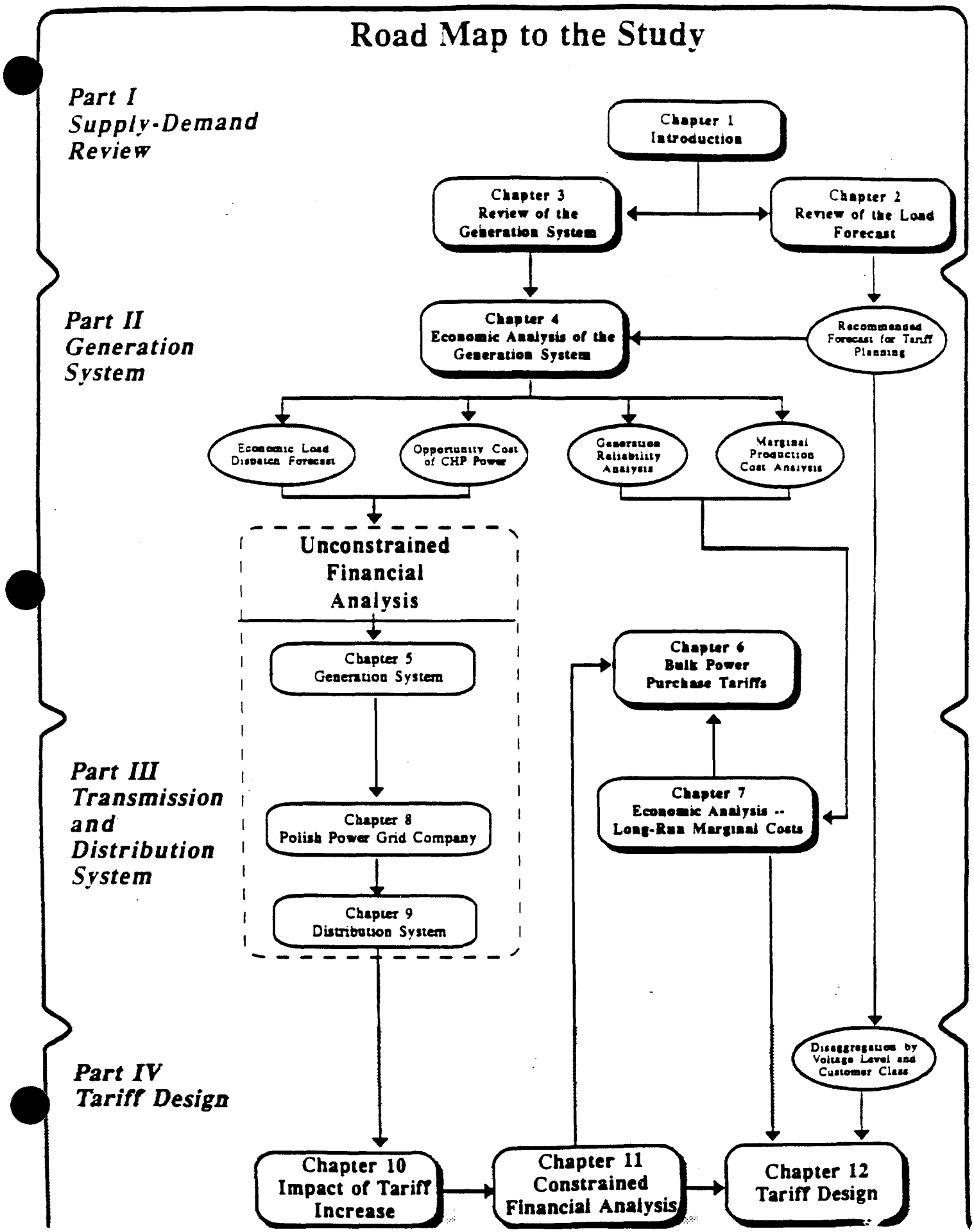


EXHIBIT S-1

# Road Map to the Study



**Poziom cen**

Wszystkie wartości pieniężne zostały wyrażone w polskich złotych (zł) przy poziomie cen z połowy 1992 roku lub w dolarach lub centach USA (c) przy zachowaniu kursu wymiany z połowy roku 1992, który wynosił 13.400 zł/USD. Analiza została przeprowadzona w wartościach rzeczywistych. Dla wyrażenia liczb w wartościach bieżących inflacja w Polsce w latach 1992 i 1993 jest szacowana na około 40 procent rocznie.

**Price Level**

All monetary values are expressed in Polish Zlotys (Zl) at mid-1992 price levels or in US dollars or cents (c) at the mid-1992 rate of exchange of 13,400 Zlotys/US$. The analysis was conducted in real terms. As a reference for converting to current values, local inflation during 1992 and 1993 is estimated to run at approximately 40 percent per year.

## S.2 FAZA PIERWSZA - ANALIZA BEZ UWZGLĘDNIANIA OGRANICZEŃ

**Bilans podaży i zapotrzebowania**

***Analiza prognozy obciążenia (Rozdział 2).*** Prognozowanie obciążenia w Polsce jest zadaniem złożonym z powodu trwającej transformacji gospodarki i będącego jej wynikiem braku ciągłości pomiędzy funkcjonalnymi wyznacznikami zapotrzebowania w przeszłości i w przyszłości. Wynikiem analizy prognozy zapotrzebowania było przyjęcie scenariusza wzrostu obciążenia dającego przeciętny wzrost sprzedaży o 1,3 procent rocznie w latach 1991-1995 oraz 2 procent rocznie w okresie kolejnych pięciu lat. Przyjęta prognoza sprzedaży w rozbiciu na kategorie odbiorców została przedstawiona na Schemacie S-2.

***Analiza podsystemu wytwarzania (Rozdział 3).*** Źródła energii w polskim systemie elektroenergetycznym można zakwalifikować do trzech kategorii: elektrownie zawodowe, elektrownie przemysłowe oraz wymiana międzynarodowa. Głównym przedmiotem zainteresowania niniejszego studium są elektrownie zawodowe.

## S.2 FIRST STAGE - UNCONSTRAINED ANALYSIS

**Supply-Demand Balance**

***Review of the Load Forecast (Chapter 2).*** Demand forecasting in Poland is complex owing to the ongoing transition of the economy and the resulting discontinuity between functional determinants of demand historically and in the future.

The review of the demand forecast concluded in the adoption of a load growth scenario that results in an average growth in sales of 1.3 percent for the period 1991-1995 and of 2 percent for the next five years. The adopted forecast of sales by customer class is shown in Exhibit S-2.

***Review of the Generation System (Chapter 3).*** The sources of energy in the Polish power system can be classified into three categories: the public system, autoproducers, and the international exchanges. The public power system is of primary concern in this study.

## Schemat S-2

# PROGNOZA OBCIĄŻENIA W WARIANCIE PODSTAWOWYM

| | | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | Średnie roczne tempo (%) 1991-96 | 1996-01 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Przemysł | WN | 28229 | 28158 | 28146 | 28410 | 29054 | 29752 | 30180 | 30746 | 31637 | 31506 | -0.4% | 1.6% |
| | SN | 17844 | 17799 | 17791 | 17958 | 18365 | 18807 | 19077 | 19435 | 19998 | 19915 | -0.5% | 1.6% |
| | NN | 2914 | 2907 | 2906 | 2933 | 2999 | 3071 | 3116 | 3174 | 3266 | 3252 | 3.3% | 1.6% |
| | Razem | 48988 | 48864 | 48843 | 49300 | 50419 | 51630 | 52372 | 53355 | 54900 | 54673 | 0.2% | 1.6% |
| Trakcja 1/ | WN | 155 | 169 | 185 | 204 | 208 | 213 | 215 | 219 | 225 | 225 | -- | - |
| | SN | 5005 | 5462 | 5973 | 6596 | 6733 | 6881 | 6967 | 7084 | 7275 | 7283 | -- | |
| | Razem | 5160 | 5631 | 6158 | 6800 | 6941 | 7094 | 7182 | 7303 | 7500 | 7508 | 7.1% | 1.6% |
| Oświetlenie Ulic | NN | 1375 | 1448 | 1527 | 1627 | 1676 | 1730 | 1768 | 1815 | 1882 | 1883 | 4.1% | 2.4% |
| Lokale Niemieskalne | SN | 1229 | 1294 | 1365 | 1454 | 1498 | 1546 | 1580 | 1622 | 1622 | 1683 | 4.0% | 2.4% |
| | NN | 7963 | 8382 | 8841 | 9417 | 9705 | 10015 | 10237 | 10509 | 10896 | 10902 | 2.5% | 2.4% |
| | Razem | 9192 | 9676 | 10206 | 10871 | 11203 | 11560 | 11817 | 12131 | 12578 | 12585 | 2.7% | 2.4% |
| Gospodarstwa Rolne | SN | 710 | 747 | 788 | 840 | 865 | 893 | 913 | 937 | 971 | 972 | 4.9% | 2.4% |
| | NN | 7712 | 8117 | 8562 | 9120 | 9399 | 9698 | 9913 | 10177 | 10552 | 10558 | 4.0% | 2.4% |
| | Razem | 8422 | 8865 | 9351 | 9960 | 10264 | 10591 | 10826 | 11114 | 11523 | 11530 | 4.1% | 2.4% |
| Gospodarstwa Domowe | NN | 21937 | 23091 | 24356 | 25943 | 26735 | 27588 | 28200 | 28949 | 30017 | 30033 | 5.1% | 2.4% |
| Razem Sprzedaż Finalna | WN | 95073 | 97574 | 100441 | 104500 | 107238 | 110194 | 112165 | 114666 | 118400 | 118212 | 2.2% | 2.0% |
| | SN | 28384 | 28327 | 28331 | 28614 | 29262 | 29965 | 30395 | 30965 | 31862 | 31731 | -0.3% | 1.6% |
| | NN | 24788 | 25302 | 25917 | 26847 | 27461 | 28127 | 28536 | 29077 | 29926 | 29582 | 1.5% | 1.7% |
| | | 41901 | 43945 | 46193 | 49040 | 50515 | 52102 | 53233 | 54624 | 56613 | 56629 | 4.2% | 2.3% |

# EXHIBIT S-2

## BASE CASE LOAD FORECAST

| | | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | Avg Annual Rate (%) 1991 - 96 | Avg Annual Rate (%) 1996 - 01 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INDUSTRY | HV | 28229 | 28158 | 28146 | 28410 | 29054 | 29752 | 30180 | 30746 | 31637 | 31506 | -0 4% | 1 6% |
| | MV | 17844 | 17799 | 17791 | 17958 | 18365 | 18807 | 19077 | 19435 | 19998 | 19915 | -0 5% | 1 6% |
| | LV | 2914 | 2907 | 2906 | 2933 | 2999 | 3071 | 3118 | 3174 | 3266 | 3252 | 3 3% | 1 6% |
| | Total | 48988 | 48864 | 48843 | 49300 | 50419 | 51630 | 52372 | 53355 | 54900 | 54673 | -0 2% | 1 6% |
| TRACTION 1/ | HV | 155 | 169 | 185 | 204 | 208 | 213 | 215 | 219 | 225 | 225 | | |
| | MV | 5005 | 5462 | 5973 | 6596 | 6733 | 6881 | 6967 | 7084 | 7275 | 7283 | | - |
| | Total | 5160 | 5631 | 6158 | 6800 | 6941 | 7094 | 7182 | 7303 | 7500 | 7508 | 7 1% | 1 6% |
| STREET LIGHTS | LV | 1375 | 1448 | 1527 | 1627 | 1676 | 1730 | 1768 | 1815 | 1882 | 1883 | 4 1% | 2 4% |
| COMMERCIAL | MV | 1229 | 1294 | 1365 | 1454 | 1498 | 1546 | 1580 | 1622 | 1682 | 1683 | 4 0% | 2 4% |
| | LV | 7963 | 8382 | 8841 | 9417 | 9705 | 10015 | 10237 | 10509 | 10896 | 10902 | 2 5% | 2 4% |
| | Total | 9192 | 9676 | 10206 | 10871 | 11203 | 11560 | 11817 | 12131 | 12578 | 12585 | 2 7% | 2 4% |
| FARMS | MV | 710 | 747 | 788 | 840 | 865 | 893 | 913 | 937 | 971 | 972 | 4 9% | 2 4% |
| | LV | 7712 | 8117 | 8562 | 9120 | 9399 | 9698 | 9913 | 10177 | 10552 | 10558 | 4 0% | 2 4% |
| | Total | 8422 | 8865 | 9351 | 9960 | 10264 | 10591 | 10826 | 11114 | 11523 | 11530 | 4 1% | 2 4% |
| RESIDENTIAL | LV | 21937 | 23091 | 24356 | 25943 | 26735 | 27588 | 28200 | 28949 | 30017 | 30033 | 5 1% | 2 4% |
| TOTAL FINAL SALES | | 95073 | 97574 | 100441 | 104500 | 107238 | 110194 | 112165 | 114666 | 118400 | 118212 | 2 2% | 2 0% |
| | HV | 28384 | 28327 | 28331 | 28614 | 29262 | 29965 | 30395 | 30965 | 31862 | 31731 | 0 3% | 1 6% |
| | MV | 24788 | 25302 | 25917 | 26847 | 27461 | 28127 | 28536 | 29077 | 29926 | 29852 | 1 5% | 1 7% |
| | LV | 41901 | 43945 | 46193 | 49040 | 50515 | 52102 | 53233 | 54624 | 56613 | 56629 | 4 2% | 2 3% |

W skład podsystemu wytwarzania, jako jednego z elementów krajowego systemu elektroenergetycznego, wchodzą elektrownie cieplne i elektrownie wodne, których łączna moc zainstalowana wynosi około 29.600 MW. Około 90 procent energii elektrycznej jest wytwarzane w elektrowniach parowych opalanych węglem kamiennym lub brunatnym pracujących wyłącznie dla krajowego systemu elektroenergetycznego, a 10 procent jest wytwarzane w elektrociepłowniach. W systemie nie ma cieplnych elektrowni szczytowych, a wahania obciążenia są regulowane w głównej mierze poprzez wykorzystanie wodnych elektrowni szczytowo-pompowych. Na schemacie S-3 przedstawiono podsumowanie systemu.

The generation component of the public power system consists of thermal and hydroelectric powerplants totalling approximately 29,600 MW of installed capacity. About 90 percent of Poland's power is produced in coal- or lignite-fired steam plants that are fully dedicated to the power sector, while 10 percent is produced in combined heat and power plants. There are no thermal peaking plants in the system and load fluctuations are mostly managed through the use of pumped storage hydroelectric. Exhibit S-3 presents a summary of this system.

Dla celów analizy ekonomicznej oszacowano, że cena węgla na granicy będzie wynosić 1,79 USD/GJ (dolarów USA na gigadżul), oraz że koszty transportu w kraju podwyższą tę cenę do 2.01 USD/GJ (koszt alternatywny z dostawą). Koszt alternatywny węgla brunatnegoSchemat S-2Schemat S-3został określony na podstawie możliwości zastąpienia nim węgla kamiennego i oszacowany na poziomie 76 procent kosztu jednostki cieplnej węgla kamiennego.

For the purposes of the economic analysis, the border price of coal was estimated to be 1.79 $/GJ (US dollars per Gigajoule) and internal transport costs were estimated to increase this price to a delivered opportunity cost of 2.01 $/GJ. The opportunity cost of lignite was derived from its potential to displace coal and was estimated at 76 percent of the cost of a thermal unit of coal.

Nominalny margines rezerwy mocy systemu wynosi ponad 40 procent. Rzeczywista rezerwa ze stałych źródeł jest rzędu 28 procent, lecz dochodzi tutaj również ważny czynnik jakim jest sezonowość zarówno obciążenia, jak i źródeł. Prognozowane efektywne rezerwy mocy, przy założeniu średniej dyspozycyjności bloków, zostały wyliczone na podstawie prognozowanego obciążenia, oczekiwanego rozwoju elektrociepłowni oraz podjętych już decyzji o budowie nowych bloków energetycznych lub wycofaniu starych. Wyliczenia te wskazują, że system posiada wystarczającą rezerwę mocy do około roku 1997, kiedy to konieczne będzie wprowadzenie nowych mocy szczytowych w postaci dodatkowych elektrowni szczytowo-pompowych, cieplnych źródeł pracujących w szczycie lub jednych i drugich. Nowe moce pracujące w obciążeniu podstawowym nie będące

The nominal capacity reserve margin of the system is over 40 percent. Actual reserves from firm resources are on the order of 28 percent, but there is also an important seasonality in both load and resources. The projected effective capacity reserves, taking into account average generating unit availabilities, were computed on the basis of forecast load, expected growth of combined heat and power plants, and the committed additions and retirements of generating units. These computations indicate that the system has adequate reserve until about the year 1997 when peaking capacity would be needed in the form of additional pumped storage hydroelectric, peaking thermal resources, or both. Base load capacity not currently under construction is not required until well into the next decade.

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# Schemat S-3
# PODSUMOWANIE PUBLICZNEGO PODSYSTEMU WYTWARZANIA
# (ELEKTROWNIE ZAWODOWE)

**POLSKA - PODSUMOWANIE PUBLICZNEGO PODSYSTEMU WYTWARZANIA**

| Elektrownia | TYP | Paliwo | Średnia Wielkść Bloków MW | Liczba Bloków MW | Moc Znamionowa MW | Moc Szczytowa MW | Procent Możliwości Systemu | Roczne Koszty Eksploatacyjne | Koszt Transportu paliwa USD/MWh | Produkcja W 1991 Roku GWh | Procent Wymagnej Produkcja |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Bełchatów | Sieć | Węgiel Brunatny | 360 | 12 | 4320 | 4320 | 15.4% | 11.27 | 0.00 | 27213 | 21.9% |
| Patnow | Sieć | Węgiel Brunatny | 200 | 10 | 2000 | 2000 | 7.1% | 12.36 | 0.00 | 7628 | 6.1% |
| Turów | Sieć | Węgiel Brunatny | 200 | 10 | 2000 | 2000 | 7.1% | 28.51 | 0.00 | 12035 | 9.7% |
| Adamow | Sieć | Węgiel Brunatny | 120 | 5 | 600 | 480 | 1.7% | 33.90 | 0.00 | 2875 | 2.3% |
| Konin | Sieć | Węgiel Brunatny | 65 | 9 | 583 | 523 | 1.9% | 30.68 | 0.00 | 3148 | 2.5% |
| Elektrowne Zawodowe Na Węgiel Brunatny | | | | | 9503 | 9323 | 33.2% | | | 52899 | 42.6% |
| Ostrołeka | Sieć | Węgiel Kamienny | 200 | 3 | 600 | 600 | 2.1% | 20.38 | 1.91 | 2864 | 2.3% |
| Kozienice | Sieć | Węgiel Kamienny | 260 | 10 | 2600 | 2600 | 9.3% | 17.94 | 1.59 | 7996 | 6.4% |
| Połaniec | Sieć | Węgiel Kamienny | 200 | 8 | 1600 | 1600 | 5.7% | 18.80 | 1.35 | 7173 | 5.8% |
| Rybnik | Sieć | Węgiel Kamienny | 200 | 8 | 1600 | 1600 | 5.7% | 20.95 | 0.68 | 9252 | 7.5% |
| Jaworzno III | Sieć | Węgiel Kamienny | 200 | 6 | 1200 | 1140 | 4.1% | 25.14 | 0.71 | 6302 | 5.1% |
| Dolna Odra | Sieć | Węgiel Kamienny | 200 | 8 | 1600 | 1600 | 5.7% | 17.42 | 2.09 | 6856 | 5.5% |
| Łaziska | Sieć | Węgiel Kamienny | 173 | 6 | 1040 | 920 | 3.3% | 29.72 | 0.37 | 4286 | 3.5% |
| Łaziska | Sieć | Węgiel Kamienny | 120 | 7 | 840 | 723 | 2.6% | 24.48 | 0.85 | 3423 | 2.8% |
| Siersza | Sieć | Węgiel Kamienny | 123 | 6 | 738 | 630 | 2.2% | 29.17 | 0.79 | 3128 | 2.5% |
| Stalowa Wola | Sieć | Węgiel Kamienny | 64 | 6 | 384 | 345 | 1.2% | 18.61 | 1.47 | 1356 | 1.1% |
| Elektrowne Na Węgiel Kamienny w Pel Dyspazycyjne | | | | | 12202 | 11758 | 41.9% | | | 52636 | 42.4% |
| W Pełni Dyspozycyjne Elektrownie Sieciowe | | | | | 21705 | 21081 | 75.2% | | | 105535 | 85.0% |
| Skawina | Sieć K | Węgiel Kamienny | 79 | 7 | 550 | 495 | 1.8% | 21.07 | 1.14 | 1919 | 1.5% |
| Jaworzno II | Sieć-K | Węgiel Kamienny | 50 | 7 | 350 | 300 | 1.1% | 22.79 | 0.87 | 904 | 0.7% |
| Blachownia | Sieć-K | Węgiel Kamienny | 47 | 6 | 282 | 244 | 0.9% | 25.60 | 1.79 | 781 | 0.6% |
| Halemba | Sieć-K | Węgiel Kamienny | 50 | 4 | 200 | 200 | 0.7% | 42.33 | 0.23 | 769 | 0.6% |
| Jaworzno | Sieć-K | Węgiel Kamienny | 29 | 5 | 145 | 93 | 0.3% | 26.97 | 0.91 | 279 | 0.2% |
| Miechowice | Sieć-K | Węgiel Kamienny | 55 | 2 | 110 | 101 | 0.4% | 30.03 | 0.04 | 295 | 0.2% |
| Pomorzany | Sieć-K | Węgiel Kamienny | 60 | 2 | 120 | 112 | 0.4% | 42.88 | 3.73 | 401 | 0.3% |
| Kolektorowe Elektrownie Sieciowe | | | | | 1757 | 1545 | 5.5% | | | 5348 | 4.3% |
| Siekierki | EC | Węgiel Kamienny | 125 | 4 | 500 | 619 | 2.2% | 37.68 | 1.91 | 1794 | 1.4% |
| Kraków | EC | Węgiel Kamienny | 115 | 4 | 460 | 446 | 1.6% | 20.30 | 1.21 | 1791 | 1.5% |
| Wrocław | EC | Węgiel Kamienny | 100 | 2 | 200 | 259 | 0.9% | 26.32 | 2.60 | 1089 | 0.9% |
| Mniejsze EC | EC | Węgiel Kamienny | 30 | 100 | 2621 | 2174 | 7.8% | 28.66 | 2.25 | 7895 | 6.4% |
| Elektrociepłownie | | | | | 4160 | 3498 | 12.5% | | | 12569 | 10.1% |
| Elektrownie | | | | | 27622 | 26124 | 93.2% | | | 123452 | 99.5% |
| Zawodowe Cieplne | | | | | 2005 | 1918 | 6.8% | | | 646 | 0.5% |
| Elektrownie Zawodowe Wodne | | | | | 2967 | 28042 | 100.0% | | | 124098 | 100.0% |
| Razem Elektrownie Zawodowe | | | | | | | | | | | |

# EXHIBIT S-3

## SUMMARY OF THE PUBLIC GENERATION SYSTEM

| POLAND – SUMMARY OF THE PUBLIC GENERATION SYSTEM | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PLANT NAME | TYPE | FUEL | MEAN UNIT CAPACITY MW | NO. UNITS | NAMEPLATE CAPACITY MW | PEAKING CAPABILITY MW | PERCENT OF SYSTEM CAPABILITY | ANNUAL OPERATING EXPENSES $/KW | FUEL TRANSPORT COST $/MWH | 1991 PRODUCTION GWH | PERCENT OF GENERATION REQUIREMENTS |
| 1 BELCHATOW | GRID | LIGNITE | 360 | 12 | 4320 | 4320 | 15.4% | 11.27 | 0.00 | 27213 | 21.9% |
| 2 PATNOW | GRID | LIGNITE | 200 | 10 | 2000 | 2000 | 7.1% | 12.36 | 0.00 | 7628 | 6.1% |
| 3 TUROW | GRID | LIGNITE | 200 | 10 | 2000 | 2000 | 7.1% | 28.51 | 0.00 | 12035 | 9.7% |
| 4 ADAMOW | GRID | LIGNITE | 120 | 5 | 600 | 480 | 1.7% | 33.90 | 0.00 | 2875 | 2.3% |
| 5 KONIN | GRID | LIGNITE | 65 | 9 | 583 | 523 | 1.9% | 30.68 | 0.00 | 3148 | 2.5% |
| LIGNITE FIRED PUBLIC PLANTS | | | | | 9503 | 9323 | 33.2% | | | 52899 | 42.6% |
| 6 OSTROLEKA B | GRID | COAL | 200 | 3 | 600 | 600 | 2.1% | 20.38 | 1.91 | 2864 | 2.3% |
| 7 KOZIENICE | GRID | COAL | 260 | 10 | 2600 | 2600 | 9.3% | 17.94 | 1.59 | 7996 | 6.4% |
| 8 POLANIEC | GRID | COAL | 200 | 8 | 1600 | 1600 | 5.7% | 18.80 | 1.35 | 7173 | 5.8% |
| 9 RYBNIK | GRID | COAL | 200 | 8 | 1600 | 1600 | 5.7% | 20.95 | 0.68 | 9252 | 7.5% |
| 10 JAWORZNO III | GRID | COAL | 200 | 6 | 1200 | 1140 | 4.1% | 25.14 | 0.71 | 6302 | 5.1% |
| 11 DOLNA ODRA | GRID | COAL | 200 | 8 | 1600 | 1600 | 5.7% | 17.42 | 2.09 | 6856 | 5.5% |
| 12 LAZISKA | GRID | COAL | 173 | 6 | 1040 | 920 | 3.3% | 29.72 | 0.37 | 4286 | 3.5% |
| 13 LAGISZA | GRID | COAL | 120 | 7 | 840 | 723 | 2.6% | 24.48 | 0.85 | 3423 | 2.8% |
| 14 SIERSZA | GRID | COAL | 123 | 6 | 738 | 630 | 2.2% | 29.17 | 0.79 | 3128 | 2.5% |
| 15 STALOWA WOLA | GRID | COAL | 64 | 6 | 384 | 345 | 1.2% | 18.61 | 1.47 | 1356 | 1.1% |
| COAL FIRED FULLY DISPATCHABLE PLANTS | | | | | 12202 | 11758 | 41.9% | | | 52636 | 42.4% |
| FULLY DISPATCHABLE GRID PLANTS | | | | | 21705 | 21081 | 75.2% | | | 105535 | 85.0% |
| 16 SKAWINA | GRID-C | COAL | 79 | 7 | 550 | 495 | 1.8% | 21.07 | 1.14 | 1919 | 1.5% |
| 17 JAWORZNO II | GRID-C | COAL | 50 | 7 | 350 | 300 | 1.1% | 22.79 | 0.87 | 904 | 0.7% |
| 18 BLACHOWNIA | GRID-C | COAL | 47 | 6 | 282 | 244 | 0.9% | 25.60 | 1.79 | 781 | 0.6% |
| 19 HALEMBA | GRID-C | COAL | 50 | 4 | 200 | 200 | 0.7% | 42.33 | 0.23 | 769 | 0.6% |
| 20 JAWORZNO I | GRID-C | COAL | 29 | 5 | 145 | 93 | 0.3% | 26.97 | 0.91 | 279 | 0.2% |
| 21 MIECHOWICE | GRID-C | COAL | 55 | 2 | 110 | 101 | 0.4% | 30.03 | 0.04 | 295 | 0.2% |
| 22 POMORZANY | GRID-C | COAL | 60 | 2 | 120 | 112 | 0.4% | 42.88 | 3.73 | 401 | 0.3% |
| COLLECTOR TYPE GRID PLANTS | | | | | 1757 | 1545 | 5.5% | | | 5348 | 4.3% |
| 23 SIEKIERTY | CHP | COAL | 125 | 4 | 500 | 619 | 2.2% | 37.68 | 1.91 | 1794 | 1.4% |
| 24 KRAKOW | CHP | COAL | 115 | 4 | 460 | 446 | 1.6% | 20.30 | 1.21 | 1791 | 1.4% |
| 25 WROCLAW | CHP | COAL | 100 | 2 | 200 | 259 | 0.9% | 26.32 | 2.60 | 1089 | 0.9% |
| 26 SMALLER CHP | CHP | COAL | 30 | 100 | 2621 | 2174 | 7.8% | 28.66 | 2.25 | 7895 | 6.4% |
| COMBINED HEAT AND POWER PLANTS | | | | | 4160 | 3498 | 12.5% | | | 12569 | 10.1% |
| PUBLIC THERMAL | | | | | 27622 | 26124 | 93.2% | | | 123452 | 99.5% |
| PUBLIC HYDROELECTRIC | | | | | 2005 | 1918 | 6.8% | | | 646 | 0.5% |
| TOTAL PUBLIC | | | | | 29627 | 28042 | 100.0% | | | 124098 | 100.0% |

jeszcze w budowie nie będą wymagane jeszcze przez kilka lat przyszłego dziesięciolecia.

Punkt ciężkości podsystemu wytwarzania jest mocno przesunięty w kierunku obciążenia podstawowego, przez co jego funkcjonowanie jest mniej wydajne niż byłoby to możliwe w innym przypadku. Takie zachwianie proporcji komplikuje również obliczenie ekonomicznych kosztów krańcowych w różnych strefach czasowych. Dzieje się tak, ponieważ podsystem musi ponosić dodatkowe koszty poza szczytem dla utrzymania wystarczającej mocy w podstawie koniecznej dla pokrycia obciążenia szczytowego, które w innym wypadku mogłoby zostać pokryte przez źródła szczytowe nie pracujące w godzinach poza szczytem.

The generation mix is heavily biased towards base load resources and this results in less efficient operation than otherwise possible. This distortion also complicates the computation of economic marginal costs by time period. This is because the system must incur additional off-peak costs to maintain sufficient base load capacity in order to meet peak loads that could otherwise be met by peaking resources that may be shut down during off-peak hours.

**Ekonomiczna analiza systemu**

***Ekonomiczna analiza podsystemu wytwarzania (Rozdziały 4, 6 i 7).*** Z przeprowadzonej analizy niezawodności systemu wynika, że można wyodrębnić następujące pory, które mogą zostać wykorzystane do określenia różnych stref czasowych w taryfach:

| | |
|---|---|
| październik-marzec | |
| szczyt ranny | 07:01 do 12:59 |
| szczyt wieczorny | 16:01 do 20:59 |
| poza szczytem | pozostałe godziny |
| kwiecień-wrzesień | |
| szczyt ranny | 07:01 do 12:59 |
| szczyt wieczorny | 19:01 do 21:59 |
| poza szczytem | pozostałe godziny |

Odpowiednie krótkoterminowe koszty krańcowe przedstawiają się następująco:

| | |
|---|---|
| październik-marzec | |
| szczyt ranny | 2,80 US c/kWh |
| szczyt wieczorny | 4,64 US c/kWh |
| poza szczytem | 2,07 US c/kWh |

**Economic Analysis of the System**

***Economic Analysis of the Generation System (Chapters 4, 6 and 7).*** The analysis of system reliability concluded that the following periods during the year have marked differences and may be used to establish differential pricing periods:

| | |
|---|---|
| October-March | |
| Morning Peak | 07:01 to 12:59 |
| Evening Peak | 16:01 to 20:59 |
| Off-Peak | all other hours |
| April-September | |
| Morning Peak | 07:01 to 12:59 |
| Evening Peak | 19:01 to 21:59 |
| Off-Peak | all other hours |

The corresponding short-run marginal costs are as follows:

| | |
|---|---|
| October-March | |
| Morning Peak | 2.80 US cents/kWh |
| Evening Peak | 4.64 US cents/kWh |
| Off-Peak | 2.07 US cents/kWh |

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| | |
|---|---|
| kwiecień-wrzesień | |
| szczyt ranny | 3,97 US c/kWh |
| szczyt wieczorny | 4,64 US c/kWh |
| poza szczytem | 2.12 US c/kWh |

Koszt uniknięty wytwarzania w systemie został obliczony przy wykorzystaniu dyferencyjnego kosztu ekonomicznego pokrycia prognozowanego obciążenia z wykorzystaniem i bez wykorzystania aktualnych mocy pochodzących z elektrociepłowni, elektrowni przemysłowych oraz elektrowni wodnych (bez szczytowo-pompowych). Szacuje się, że do roku 2010 koszt wzrośnie z obecnej wartości 4,73 c/kWh do 5,23 c/kWh.

***Długoterminowy ekonomiczny koszt krańcowy (Rozdział 7).*** Analiza długoterminowego kosztu krańcowego została przeprowadzona przez wyliczenie długoterminowych kosztów krańcowych na poziomie wytwarzania w różnych porach dnia, które to koszty są następnie przeniesione do długoterminowych kosztów krańcowych na poziomie przesyłu i rozdziału w różnych porach dnia, na różnych poziomach napięcia i u różnych kategorii odbiorców. Schemat S-4 przedstawia hurtowe i detaliczne długoterminowe koszty krańcowe i porównuje je z obecnymi stawkami.

Na poziomie detalicznym średni długoterminowy koszt krańcowy wynosi 988 zł/kWh (7,37 c/kWh), podczas gdy obecna stawka to 542 zł/kWh (4,04 c/kWh), co daje różnicę 82 procent. Na poziomie sprzedaży hurtowej długoterminowy koszt krańcowy wynosi 709 zł/kWh (5,29 c/kWh) a obecna stawka 340 zł/kWh (2,53 c/kWh), co daje różnicę 109 procent.

Zaobserwowano, że aktualnie obowiązujące taryfy znacznie odbiegają od powyższej struktury kosztów i wymagają, ogólnie mówiąc, stopniowej korekty w kierunku wyższych stawek detalicznych na poziomie niskiego napięcia w stosunku do stawek na napięciu wysokim i średnim.

| | |
|---|---|
| April-September | |
| Morning Peak | 3.97 US ¢/kWh |
| Evening Peak | 4.64 US ¢/kWh |
| Off-Peak | 2.12 US ¢/kWh |

The avoided cost of generation in the system was calculated by the differential economic cost of meeting the forecast load with and without the current block of power supplied by combined heat and power (CHP) plants, autoproducers, and hydroelectric (except pumped storage) resources. The cost is estimated to escalate from a current value of 4.73¢/kWh to 5.23¢/kWh by 2010.

***Long-Run Marginal Economic Costs (Chapter 7).*** The analysis of long-run marginal costs (LRMC) was carried out by developing the LRMC at the generation level by time-of-day and then carrying it into the LRMC at the transmission and distribution levels by time-of-day, voltage level, and customer class. Exhibit S-4 presents the bulk and retail LRMCs and compares them with the current yield.

At retail level, the average LRMC is 988 Zl/kWh (7.37¢/kWh) compared with a current yield of 542 Zl/kWh (4.04 ¢/kWh), or a difference of 82 percent. At the bulk level, the LRMC is 709 Zl/kWh (5.29 ¢/kWh) against a current yield of 340 Zl/kWh (2.53 ¢/kWh), or a difference of 109 percent.

Significant distortions from the economic cost structure above were observed in current tariffs demanding, in general, a gradual adjustment towards higher low-voltage retail tariffs in relation to high- and medium-voltage tariffs.

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## Schemat S-4

# DŁUGOTERMINOWY KOSZT KRAŃCOWY

### 'ARYFA OPARTA NA ŚCISŁYM DŁUGOTERMINOWYM KOSZCIE KRAŃCOWYM W ROZBICIU NA KLASY TARYF – SPRZEDAŻ HURTOWA

| lasa Taryf | Napięcie | Współczynnik Równoczesności | Współczynnik Obciążenia | Udziały Energii Szczyt | Udziały Energii Pół-Szczyt | Całkowity Koszt Na Miesiąc MOC tys zł/kWh | Całkowity Koszt Na Miesiąc ENERGIA tys zł/kWh | Całkowity Koszt Na Miesiąc RAZEM tys zł/kWh | Udział w Opłacie Za Moc | Sprzedaż 1992 GWh | Obecna Stawka tys zł/kWh |
|---|---|---|---|---|---|---|---|---|---|---|---|
| akłady Energetyczne | WN | 1.0 | 0.65 | 0.20 | 0.28 | 121.10 | 0.4533 | 0.7085 | 36% | 50434 | 0 3398 |
| rednia w Systemie Hurtowym | | | | 0.20 | 0.28 | 121.10 | 0.4533 | 0.7085 | | 50434 | 0 3398 |
| kwiwalent tys zł/kWh | | | | | | 0.2552 | 0.4533 | 0.7085 | | | |
| % średniej systemu | | | | | | 36% | 64% | 100% | | | |

### 'ARYFA OPARTA NA ŚCISŁYM DŁUGOTERMINOWYM KOSZCIE KRAŃCOWYM W ROZBICIU NA KLASY TARYF – SPRZEDAŻ DETALICZNA

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 'rzemysł | WN | 0.81 | 0.60 | 0.16 | 0.27 | 98.09 | 0 4354 | 0 6594 | 34% | 104090 | 0 3874 |
| | WN | 0.63 | 0.42 | 0.18 | 0.31 | 117.62 | 0.4652 | 0.8488 | 45% | 8884 | 0 4995 |
| | NN | 0.54 | 0.31 | 0.18 | 0.31 | 154.27 | 0.5203 | 1.2020 | 57% | 1334 | 0 7828 |
| 'rakcja | WN | 0.93 | 0.48 | 0.19 | 0.30 | 112.62 | 0 4534 | 0.7748 | 41% | 67 | 0 4606 |
| | SN | 0.93 | 0.48 | 0.19 | 0.30 | 173.63 | 0 4671 | 0.9627 | 51% | 2178 | 0 4715 |
| .okale | SN | 0.63 | 0.49 | 0.20 | 0.32 | 117.62 | 0.4755 | 0 8044 | 41% | 641 | 0 4934 |
| Niemieszkalne | NN | 0.55 | 0.30 | 0.20 | 0.32 | 157.13 | 0.5323 | 1.2498 | 57% | 4464 | 0 7745 |
| Gospodarstwa Wiejskie | SN | 0.54 | 0.38 | 0.20 | 0.32 | 100.82 | 0 4755 | 0.8390 | 43% | 320 | 0 5287 |
| Sprzedaż Detaliczna | NN | 0.49 | 0.25 | 0.27 | 0.25 | 139.99 | 0 5479 | 1.3150 | 58% | 13616 | 0 6310 |
| Oświetlenie Ulic | NN | 1.00 | 0.50 | 0.21 | 0.04 | 285.69 | 0.4659 | 1.2486 | 63% | 742 | 0 7884 |
| Srednia Zakładu Energetycznego | | | | 0.20 | 0.28 | 128.31 | 0.4888 | 0 9879 | | 46336 | 0 5421 |
| Ekwiwalent tys zł/kWh | | | | | | 0.4991 | 0.4888 | 0 9879 | | | |
| % średniej systemu | | | | | | 51% | 49% | 100% | | | |

# EXHIBIT S-4

## LONG RUN MARGINAL COSTS

STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS BULK

| TARIFF CLASS | SERVICE VOLTAGE | COINCI DENCE | LOAD FACTOR | ENERGY SHARES PEAK | MID PEAK | TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW | ENERGY tysZl/KWh | TOTAL tysZl/KWh | DEMAND CHARGE SHARE | III/1992 SALES GWh | CURRENT YIELD tysZl/KWh |
|---|---|---|---|---|---|---|---|---|---|---|---|
| DISTRIBUTION COS | HV | 1 00 | 0 65 | 0 20 | 0 28 | 121 10 | 0 4533 | 0 7085 | 36% | 50434 | 0 3398 |
| BULK SYSTEM AVERAGE | | | | 0 20 | 0 28 | 121.10 | 0 4533 | 0 7085 | | 50434 | 0 3398 |
| Equivalent tysZl/KWh | | | | | | 0 2552 | 0 4533 | 0 7085 | | | |
| % of System Average | | | | | | 36% | 64% | 100% | | | |

STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS RETAIL

| TARIFF CLASS | SERVICE VOLTAGE | COINCI DENCE | LOAD FACTOR | ENERGY SHARES PEAK | MID PEAK | TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW | ENERGY tysZl/KWh | TOTAL tysZl/KWh | DEMAND CHARGE SHARE | III/1992 SALES GWh | CURRENT YIELD tysZl/KWh |
|---|---|---|---|---|---|---|---|---|---|---|---|
| INDUSTRIAL | HV | 0 81 | 0 60 | 0 16 | 0 27 | 98 09 | 0 4354 | 0 6594 | 34% | 14090 | 0 3874 |
| | MV | 0 63 | 0 42 | 0 18 | 0 31 | 117 62 | 0 4652 | 0 8488 | 45% | 8884 | 0 4995 |
| | LV | 0 54 | 0 31 | 0 18 | 0 31 | 154 27 | 0 5203 | 1 2020 | 57% | 1334 | 0 7828 |
| TRACTION | HV | 0 93 | 0 48 | 0 19 | 0 30 | 112 62 | 0 4534 | 0 7748 | 41% | 67 | 0 4606 |
| | MV | 0 93 | 0 48 | 0 19 | 0 30 | 173 63 | 0 4671 | 0 9627 | 51% | 2178 | 0 4715 |
| COMMERCIAL | MV | 0 63 | 0 49 | 0 20 | 0 32 | 117 62 | 0 4755 | 0 8044 | 41% | 641 | 0 4934 |
| | LV | 0 55 | 0 30 | 0 20 | 0 32 | 157 13 | 0 5323 | 1 2498 | 57% | 4464 | 0 7745 |
| AGRICULTURAL | MV | 0 54 | 0 38 | 0 20 | 0 32 | 100 82 | 0 4755 | 0 8390 | 43% | 320 | 0 5287 |
| RETAIL | LV | 0 49 | 0 25 | 0 27 | 0 25 | 139 99 | 0 5479 | 1 3150 | 58% | 13616 | 0 6310 |
| ST LIGHTING | LV | 1 00 | 0 50 | 0 21 | 0 04 | 285 69 | 0 4659 | 1 2486 | 63% | 742 | 0 7884 |
| DISTRIBUTION COMPANY AVERAGE | | | | 0 20 | 0 28 | 128.31 | 0 4888 | 0 9879 | | 46336 | 0 5421 |
| Equivalent tysZl/KWh | | | | | | 0 4991 | 0 4888 | 0 9879 | | | |
| % of System Average | | | | | | 51% | 49% | 100% | | | |

Tys Zl = thousands of zloty

## Finansowa analiza systemu bez uwzględniania ograniczeń

*Finansowa analiza podsystemu wytwarzania bez uwzględniania ograniczeń (Rozdział 5).* Analiza finansowa podsystemu wytwarzania opiera się na szczegółowej analizie 17 pojedynczych elektrowni: czterech największych w Polsce konwencjonalnych elektrowni opalanych węglem brunatnym oraz 13 największych konwencjonalnych i kolektorowych Schemat S-4elektrowni na węgiel kamienny. Ta grupa daje 96 procent całej energii wyprodukowanej w Polsce przez elektrownie pracujące wyłącznie dla sieci.

Na prośbę konsultanta w firmie Polskie Sieci Elektroenergetyczne S.A. wykonano poważne zadanie polegające na zebraniu historycznych danych finansowych z każdej z tych elektrowni. Dane te zostały wykorzystane do opracowania finansowego modelu na arkuszu kalkulacyjnym dla każdej z elektrowni dla lat 1990 i 1991. Celem tego zadania było wypracowanie wiarygodnej pozycji wyjściowej dla przyszłych prognoz, jak również próba uchwycenia głębszych trendów i wskaźników, które mogłyby utrzymywać się również w przyszłości.

Wobec braku utrwalonego systemu regulacyjnego, w analizie finansowej musiano dokonać kilku istotnych założeń opartych bądź to o opinię PSE SA jako przejściowego ciała regulacyjnego, bądź o zalecenia konsultanta. Przyjęto założenie, że większość istniejących elektrowni nadal będzie otrzymywać stawki za energię elektryczną wyliczone na podstawie ich kosztów produkcji, lecz koszty te - w głównej mierze paliwo - będą zbliżać się w kierunku kosztów standardowych opartych na ich wartości ekonomicznej. Elektrownie nie pracujące wyłącznie dla sektora elektroenergetycznego - w szczególności elektrociepłownie oraz ewentualne nowe źródła -będą otrzymywać stawki wyliczone na podstawie ekonomicznych kosztów unikniętych energii elektrycznej.

## Unconstrained Financial Analysis of the System

*Unconstrained Financial Analysis of the Generation System (Chapter 5).* The financial analysis of the generating system is based on a detailed analysis of 17 individual plants consisting of Poland's four largest lignite-fired conventional grid plants and 13 of its largest coal-fired conventional and collector grid plants. This sample covers 96 percent of all the energy generated by grid plants in Poland.

A considerable effort was made by the Polish Power Grid Company (PPGC), at the consultants' request, to gather the historical financial data for each of the generating plants. These data were used to develop a financial spreadsheet model for each generating plant for the years 1990 and 1991. The purpose of this exercise was to provide a valid starting position for future projections, as well as to attempt to identify any underlying trends and ratios that might be expected to continue into the future.

In the absence of an established regulatory system, the financial analysis required several major assumptions based on either PPGC's opinion as the interim regulatory authority or on recommendations of the consultant. It was assumed that most existing generating plants will continue to be compensated for power on the basis of their production cost, but these costs (notably fuel) will tend towards a standard cost based on their economic value. Plants not entirely dedicated to the power sector, in particular CHP plants and eventually new resources, will be compensated on the basis of the economic avoided cost of power.

W pierwszej fazie analizy finansowej świadomie pominięto wszelkie potencjalne ograniczenia mogące stać na drodze ku pełnej reformie systemu kalkulacji cen opartego na możliwych do przyjęcia kryteriach efektywności finansowej. Najistotniejszą konsekwencją takiego podejścia była propozycja, by majątek brutto, którego aktualna wartość księgowa wynosi między jedną trzecią a jedną dziesiątą jego wartości odtworzeniowej, został przeszacowany do roku 1994, oraz by przedsiębiorstwa wytwarzające energię elektryczną musiały wypracować stopę zwrotu w wysokości 6 procent wartości przeszacowanego majątku netto.

The first stage of the financial analysis explicitly ignored any potential constraints to a full reform of the pricing system based on acceptable criteria of financial performance. The major consequence of this approach was the proposition that gross assets, currently on the books at anywhere between one-third and one-tenth of their replacement cost, be revalued by 1994 and that generating companies must earn a 6 percent rate of return on the net revalued assets.

Każda próba przeszacowania majątku w podsystemie wytwarzania najprawdopodobniej będzie się wiązać z koniecznością przeprowadzenia szczegółowego technicznego szacunku kosztów odtworzenia majątku lub potencjalnych dochodów uzyskanych z każdej elektrowni. Dla celów niniejszej analizy dokonano jedynie ogólnego szacunku kosztów odtworzenia majątku, porównując je następnie z jego aktualną wartością księgową. Wyciągnięto wniosek, że prawdopodobny wskaźnik niedoszacowania majątku wynosi sześć.

Any effort to revalue the assets in the generation system is likely to involve detailed engineering estimates of replacement costs or the potential revenue derived from each individual plant. For the purposes of this analysis, only a global estimate was made of the likely replacement cost of assets against their current book value. It was concluded that assets are probably undervalued by a factor of six.

Wyniki tej analizy wskazują, że wymagany dochód dla podsystemu wytwarzania w roku 1994 będzie wynosić średnio 489 zł/kWh (3,65 c/kWh), czyli około 63 procent więcej w wartościach rzeczywistych niż poziom przychodów w roku 1992.

The results of this analysis indicate that the 1994 revenue requirements of the generating system will average 489 Zl/kWh (3.65 c/kWh) or approximately a 63 percent real increase above the 1992 level of revenues.

***Finansowa analiza Polskich Sieci Elektroenergetycznych S.A. bez uwzględnienia ograniczeń (Rozdział 8).*** Analiza kosztów przesyłu oraz wymaganych przychodów finansowych jest w zasadzie finansową analizą PSE SA. Podobnie jak w przypadku finansowej analizy wymaganego przychodu w podsektorze wytwarzania, celem analizy finansowej PSE SA było określenie wymaganego przychodu pozwalającego firmie na sprawne funkcjonowanie na zasadach komercyjnych

***Unconstrained Financial Analysis of the Polish Power Grid Company (Chapter 8).*** The analysis of transmission costs and the required financial revenues is essentially a financial analysis of the PPGC. Following up on the financial analysis of the generating system's revenue requirements, the objective of the financial analysis of PPGC was to determine the revenue requirements the company needs to operate as a viable commercial entity.

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Spółka PSE SA powstała w październiku 1990 roku. Dlatego dostępne dane historyczne dotyczą tylko jednego pełnego roku, kończącego się 31 grudnia 1991. Co więcej, wskaźniki efektywności finansowej zostały zniekształcone przez fakt, że znakomita większość majątku przesyłowego oraz elektrownia szczytowo pompowa i związane z tym koszty eksploatacyjne zostały przekazane PSE SA dopiero w styczniu 1993 roku.

PPGC was formed in October 1990. Therefore, only one full year of historical data are available for the 12 months ending December 31, 1991. Furthermore, financial performance ratios have been distorted because the bulk of the transmission assets plus the pumped storage plant and associated operation and maintenance costs were not transferred to PPGC until January 1993.

Wyniki analizy wskazują, że w roku 1994 średni wymagany przychód spółki PSE SA będzie wynosić 563 zł/kWh (4,20 c/kWh), co stanowi wzrost o 67 procent w stosunku do poziomu przychodów w roku 1992.

The results of the analysis indicate that in 1994, PPGC would require average revenues of 563 Zl/kWh (4.20 c/kWh) or an approximate increase of 67 percent above 1992 revenue levels.

***Finansowa analiza podsystemu rozdziału bez uwzględnienia ograniczeń (Rozdział 9).*** Gdy dokonywana była niniejsza analiza Rząd Polski skłaniał się ku polityce jednakowych cen hurtowych dla wszystkich zakładów energetycznych, pozwalając każdemu zakładowi na wyznaczanie własnych cen detalicznych opartych o regulowany zysk ale uwzględniających specyficzną strukturę kosztów w każdym zakładzie.

***Unconstrained Financial Analysis of the Distribution System (Chapter 9).*** At the time this analysis was conducted, the Polish Government was leaning towards a policy of uniform bulk sales tariffs for all distribution companies, allowing each company to set its retail tariffs based on a regulated profit but taking into account the specific cost structure of each company.

Analiza kosztów rozdziału i wymaganych przychodów finansowych oraz średnich taryf na poziomie odbiorców zakładów energetycznych została oparta na skonsolidowanym, zbiorczym zestawieniu kluczowych danych z rachunków wyników i bilansów wszystkich 33 zakładów energetycznych przygotowanym przez Dyrekcję Ekonomiczną PSE SA. Istotne było jednak określenie rozpiętości, jakiej można się spodziewać wśród średnich taryf detalicznych w różnych zakładach energetycznych. Dlatego oprócz zestawienia zbiorczego dokonano analizy trzech pojedynczych zakładów energetycznych - Warszawy, Gliwic i Białegostoku, jako reprezentatywnych przedstawicieli - odpowiednio - dużego zakładu miejskiego, średniego zakładu miejskiego i zakładu w rejonie rolniczym.

The analysis of distribution costs and the required financial revenues and *average* tariff at the level of the distribution company customers was based on a consolidation or aggregation of key income statement and balance sheet data for the 33 distribution companies prepared by the Economics Department of PPGC. However, it was relevant to determine the variability that can be expected among the average retail tariffs of different distribution companies. Therefore, in addition to the consolidated case, three individual distribution companies were analyzed -- Warsaw, Gliwice and Bialystok -- which represent major urban, mid-size urban, and rural distribution companies, respectively.

Wobec braku przepisów regulujących funkcjonowanie zakładów energetycznych na zasadach komercyjnych w momencie opracowywania studium, wzięto pod uwagę trzy różne kryteria finansowe: 1) niezwiększanie się ogólnego zadłużenia, 2) 6 procent zwrotu na majątku netto, oraz 3) 100-procentowy współczynnik samofinansowania. Pierwsze kryterium zostało przyjęte jako najbardziej ostrożne i zakłada, że podsystem rozdziału musi być w stanie finansować odtwarzanie urządzeń i rozszerzanie zakresu usług z własnych przychodów.

In the absence of a regulatory policy for commercial operation of the distribution companies at the time of the study, three different financial criteria were considered: 1) no increase in overall debt, 2) 6 percent return on net assets, and 3) 100 percent self-financing ratio. The first was accepted as the most prudent and implies that the distribution system must be capable of financing its equipment replacement and extending its service coverage from its revenues.

Wyniki zbiorczej analizy podsystemu rozdziału wskazują, że średni wymagany przychód w roku 1994 wyniósłby 785 zł/kWh (5,86 c/kWh), czyli około 45 procent więcej w wartościach rzeczywistych niż poziom z roku 1992.

The results of the analysis of the consolidated distribution system indicate that the 1994 average revenue requirements would be 785 Zl/kWh (5.86 ¢/kWh) or approximately a 45 percent real increase above 1992 levels.

Analiza porównawcza wymaganych przychodów w roku 1994 dla trzech wymienionych wcześniej zakładów energetycznych daje następujące współczynniki w stosunku do wyniku zbiorczego: Białystok 1,59, Gliwice 0,99 i Warszawa 1,16. Dlatego, w takiej ograniczonej próbce, maksymalna różnica w wymaganych przychodach między dwoma zakładami energetycznymi wynosi około 60 procent.

A comparative analysis of the 1994 revenue requirements of the three distribution companies indicates the following ratios with respect to the consolidated system: Bialystok 1.59, Gliwice 0.99, and Warsaw 1.16. Therefore, in this limited sample, the maximum difference in revenue requirements between two distribution companies is approximately 60 percent.

## S.3 FAZA II - ANALIZA WPŁYWU, PROGNOZY FINANSOWE Z UWZGLĘDNIENIEM OGRANICZEŃ ORAZ OSTATECZNY UKŁAD TARYF

## S.3 STAGE II - ANALYSIS OF IMPACT, CONSTRAINED FINANCIAL PROJECTIONS AND FINAL TARIFF DESIGN

Do kwietnia 1993 roku dwie sprawy stawały się coraz bardziej jasne. Po pierwsze, wydawało się mało prawdopodobne, by dokonano znacznych postępów w roku 1993 jeśli chodzi o realny wzrost poziomu cen na energię elektryczną, przez co proponowany poziom z roku 1994 w rzeczywistości stanowiłby 45 procent realnego wzrostu w porównaniu z rokiem 1993. Po drugie, zachodziłyby poważne przeszkody dla nagłego przeszacowania majątku do jego pełnej

By April 1993 two things were becoming increasingly clear. First, it seemed unlikely that much progress would be made during 1993 in terms of real growth in tariff levels. Therefore, the proposed 1994 level would in effect represent a 45 percent real rate of increase with respect to 1993. Second, there would be serious constraints to a sudden revaluation of assets to their full replacement cost. Furthermore, even if assets could

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wartości odtworzeniowej, a ponadto, nawet jeśli majątek mógłby być stopniowo przeszacowany do pełnej wartości odtworzeniowej, to wydawało się mało prawdopodobne, by odpisy amortyzacyjne dla celów podatku dochodowego mogły być oparte na pełnej wartości odtworzeniowej.

gradually be revalued to full replacement cost, it was unlikely that depreciation allowances for income tax purposes could be based on full replacement cost.

Okoliczności te zostały uwzględnione w drugiej fazie studium w postaci analizy wpływu cen i prognozy finansowej opartej na stopniowym procesie przeszacowywania majątku.

These circumstances were incorporated in the second stage of the study in the form of an analysis of tariff impact and a financial forecast based on a gradual process of asset revaluation.

**Wpływ wzrostu cen (Rozdział 10)**

**Impact of Tariff Increases (Chapter 10)**

Dokonano oceny wpływu wzrostu cen energii elektrycznej na odbiorców detalicznych w Polsce w celu dokonania korekty cen z ich obecnego poziomu do poziomu wynikającego z pełnej kalkulacji kosztowej. Analiza koncentrowała się na wpływie zarówno na wydajność ekonomiczną, jak i na budżety domowe.

An assessment was made of the impact of electricity tariff increases on Poland's end-users in order to adjust prices from their current levels to full cost-based pricing. The analysis focused both on the impact upon the economic output and the impact on household budgets.

Istnieje szereg czynników komplikujących analizę wpływu wzrostu cen na poszczególne gałęzie przemysłu w Polsce, jak na przykład fakt, że przed 1990 rokiem wewnętrzne bodźce dla polskiego przemysłu były skierowane w złą stronę, a często redukcja kosztów wiązała się z redukcją zysku. Szacuje się, że energia elektryczna stanowi przeciętnie około 3,4 procent kosztów w przemyśle. Wyciągnęliśmy więc z tego wniosek, że koszty energii elektrycznej prawdopodobnie nie są największym problemem, przed jakim stoi obecnie polski przemysł. Problemy związane z prywatyzacją, zmianą cen produktów, zmieniającą się technologią, przesunięciami w wyborze produktów, obniżonym ogólnym popytem oraz wprowadzaniem normalnych bodźców rynkowych są prawdopodobnie dużo istotniejsze niż realna podwyżka cen energii elektrycznej.

A number of factors complicate the analysis of the impact of tariff increases on Poland's industries including the fact that, prior to 1990, internal incentives for Polish industry were perverse, and in many cases, cost reductions resulted in reduced profit. It was estimated that electricity accounts for about 3.4 percent of industrial costs on average. We thus concluded that electricity costs are probably not the largest problem facing Polish industry at this time. The problems associated with privatization, changing product prices, changing technology, shifts in product choice, depressed aggregate demand, and the installation of normal market incentives are probably far more critical than rising real electricity prices.

Pod koniec 1992 roku szacowano, że realna podwyżka cen energii elektrycznej o 75 procent mogłaby zwiększyć wydatki z budżetu domowego o około 2,5 do 3 procent dochodów rodziny, z

As of late 1992 it was estimated that a 75 percent real increase in electricity prices could increase household expenditures by about 2.5 to 3 percent of incomes. Of this, 2 to 2.25

czego 2,0 do 2,25 procent byłoby bezpośrednim wynikiem zużycia energii, a 0.6 procent byłoby związane z wyższymi cenami żywności. Inne artykuły konsumpcyjne miałyby bardzo niewielki wpływ. Na tej podstawie mogło by się w pierwszej chwili wydawać, że wpływ dużej podwyżki cen energii elektrycznej na budżety domowe byłby mało istotny. Jednak jeśli weźmie się pod uwagę szybko rosnące ceny wszystkich rodzajów energii i innych artykułów, podwyżka ta staje się bardziej odczuwalna. Poza tym, nawet 3-procentowa podwyżka wydatków z już bardzo napiętego budżetu domowego ma olbrzymie znaczenie.

percent would be through the direct use of electricity and 0.6 percent through higher food prices. Other consumption items would have very small effects. On this basis, the impact of a large electricity tariff increase on household budgets may at first appear negligible. However, taken in the context of rapidly rising prices in all sources of energy and in other sectors of the economy, the adjustments appear more burdensome. Further, even a 3 percent increase household budget expenses is dramatic if resources are strained.

Na podstawie dyskusji z PSE SA oszacowano, że realna podwyżka cen rzędu 10 do15 procent rocznie stanowi górną granicę średniej rocznej korekty cen w górę akceptowalnej dla polskich budżetów domowych w obecnych warunkach ekonomicznych.

Based on discussions with PPGC, it was estimated that real tariff increases on the order of 10 to 15 percent per year represent the maximum average annual upward adjustment of prices acceptable to Polish household budgets in today's economic environment.

**Analiza finansowa z uwzględnieniem ograniczeń (Rozdział 11)**

Przeprowadzono kilka projekcji finansowych, które uwzględniały ograniczenia we wzroście cen energii elektrycznej i stopie przeszacowania majątku. Scenariusz, który został uznany za najbardziej odpowiedni dla aktualnej sytuacji w Polsce, uwzględnia stopniowe przeszacowanie majątku do jego pełnej wartości odtworzeniowej do roku 1997, przy jednoczesnym zachowaniu pułapu 70 procent wartości odtworzeniowej dla obliczenia odpisów amortyzacyjnych dla celów podatkowych.

**Constrained Financial Analysis (Chapter 11)**

Several financial projections were made taking into account limitations on the rate of tariff increase and the rate of asset revaluation. The scenario considered most compatible with current realities in Poland includes gradual asset revaluation to full replacement cost by 1997 with a ceiling of 70 percent of replacement cost to compute depreciation allowances for tax purposes.

Ponadto, za limit akceptacji społecznej dla wzrostu cen na energię elektryczną uznano pułap 15 procent rocznie oraz przyjęto założenie, że w okresie od połowy 1992 roku do stycznia 1994 roku osiągnięte zostanie jedynie 7 procent realnego wzrostu cen.

A ceiling of 15 percent on the annual rate of increase in tariffs from 1994 onwards was also imposed as the limit of public acceptance, and it was assumed that only a 7 percent real increase would be achieved between mid-1992 and January 1994.

Najistotniejsze prognozy finansowe oparte na tych założeniach zostały podsumowane w schemacie S-5. Prognozy te pokazują, że otrzymany w ten sposób wymagany dochód na poziomie sprzedaży detalicznej wynosi 623 zł/kWh (4,65 c/kWh) w roku 1994, 716 zł/kWh (5,34 c/kWh) w roku 1995, a następnie 814 zł/kWh (6,07 c/kWh) dla lat 1996 i 1997.

Key financial projections based on these assumptions are summarized in Exhibit S-5. These projections show that the resulting average revenue requirements at the retail level are 623 Zl/kWh (4.65 ¢/kWh) for 1994, 716 Zl/kWh (5.34 ¢/kWh) for 1995, and 814 Zl/kWh (6.07 ¢/kWh) for 1996 and 1997.

**Układ taryf (Rozdział 12)**

Całą energię sprzedawaną w kraju przez PSE SA kupują 33 zakłady energetyczne, które z kolei sprzedają energię odbiorcom finalnym. Ceny dla każdego zakładu są korygowane w celu zapewnienia jednakowych cen detalicznych w całym kraju dla odbiorców finalnych. W październiku 1992 roku średnia cena uzyskiwana przez PSE SA w sprzedaży hurtowej wynosiła 334,6 zł/kWh, a szacuje się, że w lutym 1993 roku nominalnie będzie wynosić 381,4 zł/kWh (339,8 zł/kWh w cenach z połowy 1992 roku).

Poniżej przedstawione są główne cechy taryfy, która weszła w życie dnia 1 stycznia 1993 roku (Nr. 7-Z/92).

- Taryfa jest oparta całkowicie na poziomie napięcia, na jakim odbiorca pobiera energię, z możliwością wyboru strefy czasowej oferowaną w każdej kategorii odbiorców.
- Jak wynika z danych na temat sprzedaży w pierwszej połowie 1992 roku, taryfa "A" (wysokie napięcie, 60 do 220 kV) stanowi około 31 procent całkowitej sprzedaży.
- Odbiorcy z taryfy "B" (średnie napięcie, 1 do 60 kV) stanowią około 26 procent całkowitej sprzedaży. Wszyscy ci odbiorcy płacą zarówno za moc, jak i energię.
- Taryfa "C" (niskie napięcie, poniżej 1 kV)

**Tariff Design (Chapter 12)**

All of PPGC's domestic bulk sales are to 33 independent distribution companies, which in turn resell electricity to final consumers. Tariffs to each company are adjusted to permit uniform national tariffs to these end-users. PPGC's average yield on bulk sales was 334.6 Zl/kWh in October 1992, and is estimated to be a nominal 381.4 Zl/kWh as of February 1993 (339.8 Zl/kWh at mid-1992 prices).

The following are the principal features of the tariff structure that came into effect on January 1, 1993 (No. 7-Z/92).

- Tariffs are based strictly on consumer service voltage, with time-of-day rate options offered for each class.
- Based on billed sales data for the first half of 1992, tariff "A" (High Voltage, 60 to 220 kV) represents approximately 31 percent of total sales.
- Tariff "B" (Medium Voltage, 1 to 60 kV) customers account for about 26 percent of total sales. All of these customers pay both demand and energy charges.
- Tariff "C" (Low Voltage, below 1 kV) is divided into two classes. The first is

Schemat S-5

## ANALIZA FINANSOWA Z UWZGLĘDNIENIEM OGRANICZEŃ
### Ograniczenie podwyżek cen i stopniowe przeszacowywanie majątku ("najbardziej prawdopodobny wariant")

Założenia:
Podwyżka cen detalicznych: od połowy 1992 do połowy 1994: 15%, potem 15% rocznie realnie
Przeszacowanie majątku: 100% kosztu odtworzenia do stycznia 1997
Odpisy podatkowe od amortyzacji: 70% kosztu odtworzenia do stycznia 1997
Inwestycje w podsystem wytwarzania 1993-1997: 5,8 miliarda USD
Stałe koszty eksploatacyjne: malejące
Finansowe kryteria dla ZE: niezaciąganie pożyczek

| | Estimate 1992 | Forecast | | | |
|---|---|---|---|---|---|
| | | 1994 | 1995 | 1996 | 1997 |
| **ŚREDNIE CENY - zł/kWh (poziom cen z połowy 1992 roku)** | | | | | |
| Zakłady Energetyczne | 542.1 | 623.4 | 716.9 | 814.0 | 814.0 |
| PSE | 336.7 | 378.0 | 411.0 | 517.0 | 567.0 |
| Podsystem wytwarzania | 300.0 | 307.0 | 337.0 | 446.0 | 494.0 |
| **ŚREDNIE CENY - centy USA/kWh (pozium cen z połowy 1992 roku)** | | | | | |
| Zakłady Energetyczne | 3.99 | 4.58 | 5.27 | 5.99 | 5.99 |
| PSE | 2.48 | 2.78 | 3.02 | 3.80 | 4.17 |
| Podsystem wytwarzania | 2.21 | 2.26 | 2.48 | 3.28 | 3.63 |
| **BILANS POŻYCZEK/NIEDOBÓR (NADWYŻKA) GOTÓWKI (miliardy zł)** | | | | | |
| Zakłady Energetyczne | | 165 | 203 | 199 | 219 |
| PSE - planowane długoterminowe pożyczki | | 4000 | 7,250 | 10,000 | 10,250 |
| gotówka | | (1,738) | (2,597) | (3,429) | (5,520) |
| Podsystem wytwarzania | | 19,942 | 29,399 | 34,032 | 34,356 |
| **WSPÓŁCZYNNIK SAMOFINANSOWANIA - %** | | | | | |
| Zakłady Energetyczne | | 113.3 | 124.5 | 114.0 | 103.0 |
| PSE | | 11.8 | 9.5 | 18.8 | 87.0 |
| **WSPÓŁCZYNNIK DŁUGU DO MAJĄTKU WŁASNEGO (po przeszacowaniu) - %** | | | | | |
| Zakłady Energetyczne | | 1.8 | 1.4 | 1.1 | 1.0 |
| PSE | | 24.8 | 34.8 | 38.9 | 34.2 |
| Podsystem wytwarzania | | 28.6 | 34.3 | 34.7 | 34.2 |
| **ZWROT NA MAJĄTKU NETTO (po przeszacowaniu) - %** | | | | | |
| Zakłady Energetyczne | | 15.1 | 18.0 | 10.8 | 2.8 |
| PSE | | 6.4 | 6.0 | 6.1 | 5.9 |
| Podsystem wytwarzania | | (9.9) | (5.4) | 4.3 | 6.0 |
| **PODATEK DOCHODOWY ZA ROK - (miliardy zł)** | | | | | |
| Zakłady Energetyczne | | 5,576 | 8,055 | 6,886 | 3,646 |
| PSE | | 543 | 656 | 771 | 773 |
| Podsystem wytwarzania | | (2,664) | (2,409) | 1,245 | 2,338 |
| Razem | | 3,455 | 6,302 | 8,902 | 6,757 |

# EXHIBIT S-5

## CONSTRAINED BY FINANCIAL ANALYSIS

### Tariff Increase Restriction and Gradual Asset Revaluation
### ("most likely case")

Assumptions:

Retail tariff increase: from mid – 1992 to mid – 1994, 15% ; then 15% per year in real terms

Asset Revaluation: 100% of replacement cost by January 1997

Tax allowance from Depreciation: 70% of replacement cost by January 1997

Investments in generation 1993 – 1997: US$ 5.8 billion

Fixed Operation Costs: decreasing

Financial criteria for DCs: no borrowing

| | ESTIMATE | FORECAST | | | |
|---|---|---|---|---|---|
| | 1992 | 1994 | 1995 | 1996 | 1997 |
| **AVERAGE TARIFFS – Zl/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 542.1 | 623.4 | 716.9 | 814.0 | 814.0 |
| PSE | 336.7 | 378.0 | 411.0 | 517.0 | 567.0 |
| Generation System | 300.0 | 307.0 | 337.0 | 446.0 | 494.0 |
| **AVERAGE TARIFFS – US cents/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 3.99 | 4.58 | 5.27 | 5.99 | 5.99 |
| PSE | 2.48 | 2.78 | 3.02 | 3.80 | 4.17 |
| Generation System | 2.21 | 2.28 | 2.48 | 3.28 | 3.63 |
| **NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)** | | | | | |
| Distribution Companies | | 165 | 203 | 199 | 219 |
| PSE -- Programmed LTD | | 4.000 | 7.250 | 10.000 | 10.250 |
| Cash | | (1.738) | (2.597) | (3.429) | (5.520) |
| Generation System | | 19.942 | 29.399 | 34.032 | 34.356 |
| **SELF-FINANCING RATIO – %** | | | | | |
| Distribution Companies | | 113.3 | 124.5 | 114.0 | 103.0 |
| PSE | | 11.8 | 9.5 | 18.8 | 87.0 |
| **DEBT-TO-EQUITY (revalued) RATIO – %** | | | | | |
| Distribution Companies | | 1.8 | 1.4 | 1.1 | 1.0 |
| PSE | | 24.8 | 34.8 | 38.9 | 34.2 |
| Generation System | | 28.6 | 34.3 | 34.7 | 34.2 |
| **RETURN ON NET ASSETS (revalued) – %** | | | | | |
| Distribution Companies | | 15.1 | 18.0 | 10.8 | 2.8 |
| PSE | | 6.4 | 6.0 | 6.1 | 5.9 |
| Generation System | | (9.9) | (5.4) | 4.3 | 6.0 |
| **INCOME TAX FOR YEAR – billions Zl.** | | | | | |
| Distribution Companies | | 5.576 | 8.055 | 6.886 | 3.646 |
| PSE | | 543 | 658 | 771 | 773 |
| Generation System | | (2.684) | (2.409) | 1.245 | 2.338 |
| Total | | 3.455 | 6.302 | 8.902 | 6.757 |

z nich to odbiorcy o mocy maksymalnej powyżej 40 kW lub zużyciu energii większym niż 80 MWh na rok (taryfa "C2"), stanowiący około 3 procent całkowitej sprzedaży. Druga klasa to odbiorcy zużywający mniej niż 40 kW lub 80 MWh/rok (bez gospodarstw domowych), którzy stanowią w przybliżeniu 11 procent całkowitej sprzedaży. Tylko pierwsza z powyższych klas ponosi opłaty za moc.

- Odbiorcy z gospodarstw domowych i małych gospodarstw wiejskich (taryfa "G") stanowią pozostałe 29 procent sprzedaży detalicznej w systemie.

Choć obecne klasy taryfowe nie klasyfikują odbiorców w tradycyjny sposób, klasyfikacji takiej można dokonać na podstawie struktury taryf obowiązującej w roku 1992 (Nr 7-Z/91). Wynika z niej, że około 52 procent całkowitej sprzedaży przypada na sektor przemysłowy.

Na podstawie najbardziej prawdopodobnego scenariusza finansowego oraz na podstawie struktury kosztów krańcowych opracowanej w analizie ekonomicznej przygotowano szczegółowe taryfy na rok 1994, które są przedstawione w schemacie S-6.

## S.4 WNIOSKI I ZALECENIA

### Wnioski

- Polski system elektroenergetyczny ma dość duży margines rezerwy mocy wynikający z bardzo niskiego wzrostu zapotrzebowania w ciągu kilku ostatnich lat. Jednak nawet w warunkach skromnego wzrostu gospodarczego system będzie wymagać dodatkowych mocy szczytowych już w roku 1997, by móc pokonać problemy eksploatacyjne związane z dużym proporcjonalnym udziałem mocy podstawowej. Ponadto, z

customers with maximum demand above 40 kW or consumption over 80 MWh/year (tariff "C2"), which account for about 3 percent of total sales. The second is non-residential customers consuming less than 40 kW or 80 MWh/year (tariff "C1"), which comprise approximately 11 percent of total sales. Only the former group is assessed a demand charge.

- Residential and small farm customers (tariff "G") account for the remaining 29 percent of system retail sales.

Although the current tariff classes do not follow traditional customer classifications, these can be estimated from the tariff structure that was in effect throughout 1992 (No. 7-Z/91). This reveals that approximately 52 percent of total final sales go to the industrial sector.

Based on the most likely financial scenario and on the marginal cost structure developed through the economic analysis, specific tariffs for 1994 were developed as shown in Exhibit S-6.

## S.4 CONCLUSIONS AND RECOMMENDATIONS

### Conclusions

- The Polish power system has a fairly high level of capacity reserve due to very low growth in demand over the last few years. However, even under modest growth in economic activity, the system will need additional peaking capacity as early as 1997 to overcome operational problems related to the high proportion of base load generation. Furthermore, intense investments will

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**Schemat S-6**
**Udział w przychodach według klasy odbiorców i taryfy**

| | Obecna stawka | Ścisły LRMC* | | Udział w przychodach |
|---|---|---|---|---|
| **Klasa taryf** | **zł/kWh** | **zł/kWh** | **zł/kWh** | **% zmiany** |
| Sprzedaż hurtowa | 340 | 709 | 376 | 11% |
| Sprzedaż detaliczna | | | | |
| "A" | 388 | 660 | 416 | 7% |
| "B" | 495 | 867 | 547 | 11% |
| "C" (>40 kW) | 783 | 1.202 | 759 | -3% |
| "C" (<40 kW) | 775 | 1.250 | 789 | 2% |
| Odbiorcy detaliczni ("G") | 631 | 1.315 | 830 | 31% |
| Oświetlenie ulic | 788 | 1.249 | 788 | 0% |
| Średnio odbiorcy detaliczni | 542 | 988 | 623 | 15% |

LRMC - długoterminowy koszt krańcowy

**Exhibit S-6**
**Revenue Responsibility by Class and Tariff Design**

| | Current Yield | Strict LRMC | | Revenue Responsibility |
|---|---|---|---|---|
| **Tariff Class** | **Z1/kWh** | **Z1/kWh** | **Z1/kWh** | **% Change** |
| Bulk Sales | 340 | 709 | 376 | 11% |
| Retail Sales | | | | |
| "A" | 388 | 660 | 416 | 7% |
| "B" | 495 | 867 | 547 | 11% |
| "C" (>40 kW) | 783 | 1,202 | 759 | -3% |
| "C" (<40 kW) | 775 | 1,250 | 789 | 2% |
| Retail ("G") | 631 | 1,315 | 830 | 31% |
| St. Lighting | 788 | 1,249 | 788 | 0% |
| Average Retail | 542 | 988 | 623 | 15% |

harmonogramu modernizacji systemu wynikają wielkie nakłady inwestycyjne, które są konieczne dla osiągnięcia ambitnych celów w zakresie sprawności eksploatacyjnej i ochrony środowiska.

be needed under the modernization schedule required to meet ambitious targets of operating efficiency and environmental quality.

- Polskie elektrownie są obecnie zbyt słabe, by wziąć na siebie duże obciążenia finansowe; wynika to głównie z bardzo niskiej wartości księgowej ich majątku w stosunku do prawdopodobnego kosztu odtworzenia. Przeszacowanie majątku do jego przybliżonej wartości odtworzeniowej oraz przyznanie rozsądnie atrakcyjnych stóp zwrotu od majątku netto dałoby przychody finansowe konieczne dla zaspokojenia większości potrzeb, lecz wiązałoby się to z nagłym wzrostem cen energii elektrycznej w roku 1994. W cenach stałych (czyli nie uwzględniając inflacji) wzrost wyniósłby około 45 procent w porównaniu ze średnimi cenami z roku 1992.

- Polish power plants are currently in a weak position to assume heavy financial obligations, largely because of the very low book value of their assets in relation to their likely replacement cost. Revaluation of assets to their approximate replacement cost and the allowance of reasonably attractive rates of return on their net value would generate the financial revenues necessary to meet most needs, but this would result in a steep rise in the electricity prices for 1994. In constant price levels (that is, excluding inflation), the increase would be approximately 45 percent with respect to average tariffs during 1992.

- Stopniowe przeszacowanie majątku jest uważane za bardziej prawdopodobne i dałoby przeciętny wzrost cen nie większy niż 15 procent każdego roku, a ceny osiągnęłyby stabilny poziom w roku 1996. W celu pokrycia potrzeb systemu przy niższych przychodach ze sprzedaży w latach 1994 i 1995 podsystem wytwarzania musiałby zaciągnąć pożyczki na sumę około 2,9 miliarda USD. Takie założenie stanowiło podstawę dla określenia poziomu cen detalicznych dla roku 1994, a struktura taryf została oparta na szacunkowym koszcie krańcowym usługi świadczonej różnym klasom odbiorców.

- A gradual revaluation of assets is considered more likely and would result in average tariffs increases of not more than 15 percent from one year to the next, reaching a stable value by 1996. To meet the needs of the system with lower revenues from sales during 1994 and 1995, the generation system would need to borrow approximately US $2.9 billion. Retail tariff levels for 1994 were based on this assumption and the tariff structure was based on the estimated marginal cost of service to different customer classes.

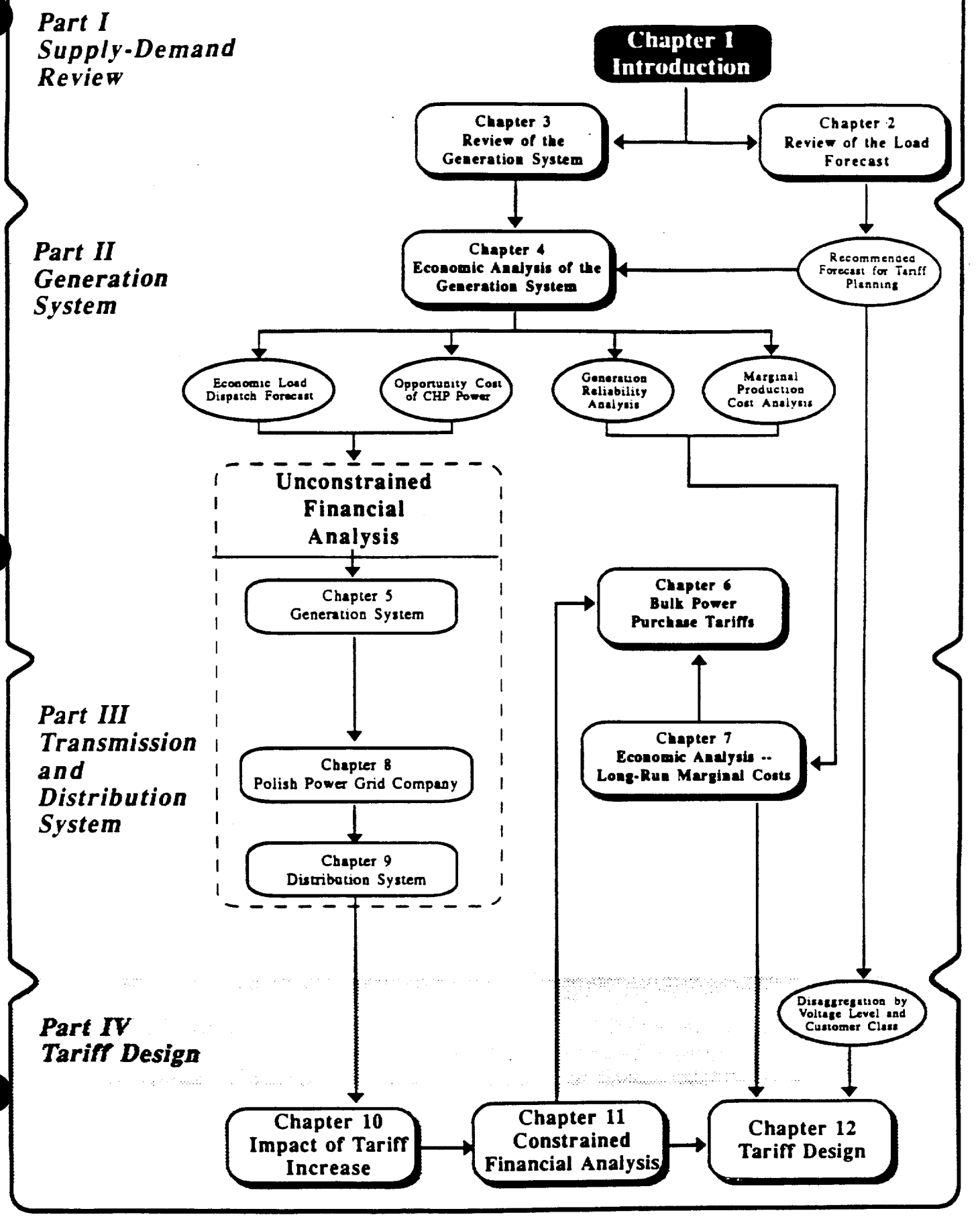
**Zalecenia**

- Zdecydowana większość dużych elektrowni cieplnych powinna nadal

**Recommendations**

- The bulk of the large thermal generating plants should continue to be compensated on the basis of their

# Road Map to the Study



# CHAPTER 1: INTRODUCTION

## 1.1 STUDY BACKGROUND AND OBJECTIVES

As Poland changes from a centrally planned to a free market economy, the government is beginning to divest its ownership and control of virtually all means of production. In the power sector, such structural reform is particularly important because they lead to the vertical and horizontal disaggregation of a tightly integrated system of powerplants, system control, and transmission and distribution networks.

One of the primary activities in the reform of the energy sector is the elimination of subsidies and barriers to free competition, which will revitalize the sector and provide competitively priced energy to industry, business and households. Fundamental to achieving this objective is the rationalization of both the levels and structure of electricity pricing. This will provide buyers and sellers of electricity with the correct signals to make economically optimal investment and consumption decisions.

The objectives of this study are to design retail and bulk power tariffs for the medium term based on marginal cost principles, to develop transfer price principles consistent with the rationalization of the power sub-sector, and to provide practical guidelines for the implementation and phase-in of the new pricing system.

This study has been funded under the Regional Energy Efficiency Project (180-0030) of the United States Agency for International Development (A.I.D.). RCG/Hagler, Bailly, Inc. wishes to acknowledge the assistance and cooperation received from many Polish and international organizations during the execution of the study and in particular, the Polish Power Grid Company, A.I.D., and the World Bank.

## 1.2 OVERVIEW OF THE POLISH POWER SYSTEM

### 1.2.1 The Power System and Electricity Market

The Polish power industry was virtually destroyed by the end of World War II and was developed to its current form during the period 1950-1990. However, because of Poland's difficulties in obtaining financing and access to western technologies during that period, the characteristics of its electric system are substantially different from those of modern systems of comparable size in western countries.

By the end of 1990, Poland had 394 power and combined heat and power (CHP) stations with a total installed capacity of about 32,000 MW. This included 220 industrial CHP stations, 55 publicly owned thermal plants, and 119 hydroelectric powerplants. Out of the 2,000 MW of hydroelectric capacity, 1,500 MW are installed in five pumped storage plants with little net generation. Virtually all (99.5 percent) of the country's power is produced in thermal plants equipped exclusively with steam turbines that use lignite and coal as their primary fuels.

The high-voltage transmission grid consists of 220 kV, 400 kV and 750 kV lines totalling some 12,300 km. These and the system control facilities are managed by the Polish Power Grid Company (PPGC) or polish acronym (PSE). There are 48 companies involved in the distribution of power and heat in Poland.

Poland's power consumption patterns have been changing drastically since 1988, with a growing proportion accounted for by households and non-industrial consumers. Currently, industrial consumers account for 56 percent of sales, urban households for 28 percent, and commercial customers for 9 percent.

Poland exchanges electricity with several countries, and the number of these exchanges has been growing steadily since 1990. In 1992, Poland's net exports were approximately 4,000 GWh, or about 3 percent of final sales.

### 1.2.2 Power Sector Reform

The Polish Government, in agreement with the World Bank, has prepared and implemented a wide restructuring program in the past two years. One of the program's first accomplishments was to create in August 1990 the Polish Power Grid Company, which is fully owned by the National Treasury. Among other things, the program envisages the following:

- reorganization of all lignite mining enterprises and lignite-fired power stations into three regional organizations.
- reorganization of coal-fired powerplants into four commercial generating utilities
- reorganization of combined heat and power facilities into nine commercial utilities

- commercialization and privatization of enterprises auxiliary to the power industry

- reorganization of the distribution companies into 10 to 20 regional distribution utilities.

A regulatory authority is expected to be created to protect the public and supervise the fair operation of the power market. In the meantime the Ministry of Industry and Trade, through PPGC, supervises the entire power industry. Its responsibilities include system planning, system dispatch and control, bulk power purchases and sales, and retail tariff recommendations.

In the absence of detailed regulatory guidelines the tariff study had to adopt assumptions regarding acceptable financial performance criteria for the different components of the system. These were guided by broad principles of operation and administration of the power sector defined by PPGC which direct the power system towards standards of efficiency and environmental quality that are comparable to those of western European countries.

## 1.3 ROAD MAP TO THE TARIFF STUDY

The report on the tariff study is structured into four parts, each containing three chapters:

- Part I - Supply and Demand Review
- Part II - Generation System
- Part III - Transmission and Distribution System
- Part IV - Tariff Design

The structure follows the analytical flow of the study and is shaped by the uncertainties faced during its execution. The most important aspect of the structure of the report is that Part I does not necessitate any assumptions about external constraints such as the feasibility of revaluating the power sector's assets and the feasibility of electricity tariff increases; Parts II and III assume that these external constraints do not exist, while Part IV takes them into consideration. This complexity is required because of the iterative nature of the tariff design process. A description of the contents of each part follows.

***Part I: Supply and Demand Review.*** This part of the report includes this introductory chapter and a review of the two extreme points of the power market, namely the demand for power and power generation resources. The demand for power is reviewed in Chapter 2

with respect to both total sales and the distribution of power demand by consumer groups and voltage levels. The generation system is reviewed in Chapter 3 and includes the main assumptions regarding the evolution of the generation system, the adequacy of the system to meet demands for power, and the principles for the sale of bulk power from generating companies.

*Part II: Transmission and Distribution System.* In this part of the report, the generation system is studied in greater detail and from two compatible but very different perspectives. In Chapter 4 the generation system is examined from the point of view of the Polish economy and includes a simulation of the system based on economic price levels. This chapter has two major outputs. The first is the forecast of production, by plant, for the 1993-2000 period; the second is the analysis of the system reliability and marginal production costs for two specific years, 1994 and 1997.

In Chapter 5 the generation system is examined from the perspective of the generating companies. Thus, while the production of each plant is derived from the forecast of Chapter 4, the production cost includes all financial costs. The final result is a computation of all the revenues that generating companies need to collect in order to provide power. These comprise all of the costs included in the economic analysis plus other costs such as taxes, interest on loans, amortization of revalued assets, and the profit that is deemed necessary for power generation to be an attractive commercial industry. It is emphasized that this forecast is not yet adjusted by any considerations about the feasibility of asset revaluation or tariff increases and is therefore is called the "unconstrained financial analysis of the generation system."

Part II ends with Chapter 6 in which the economic principles established to structure the sale of power from generating plants are combined with the financial revenue requirements to determine a bulk power tariff for transactions between generators and the power grid.

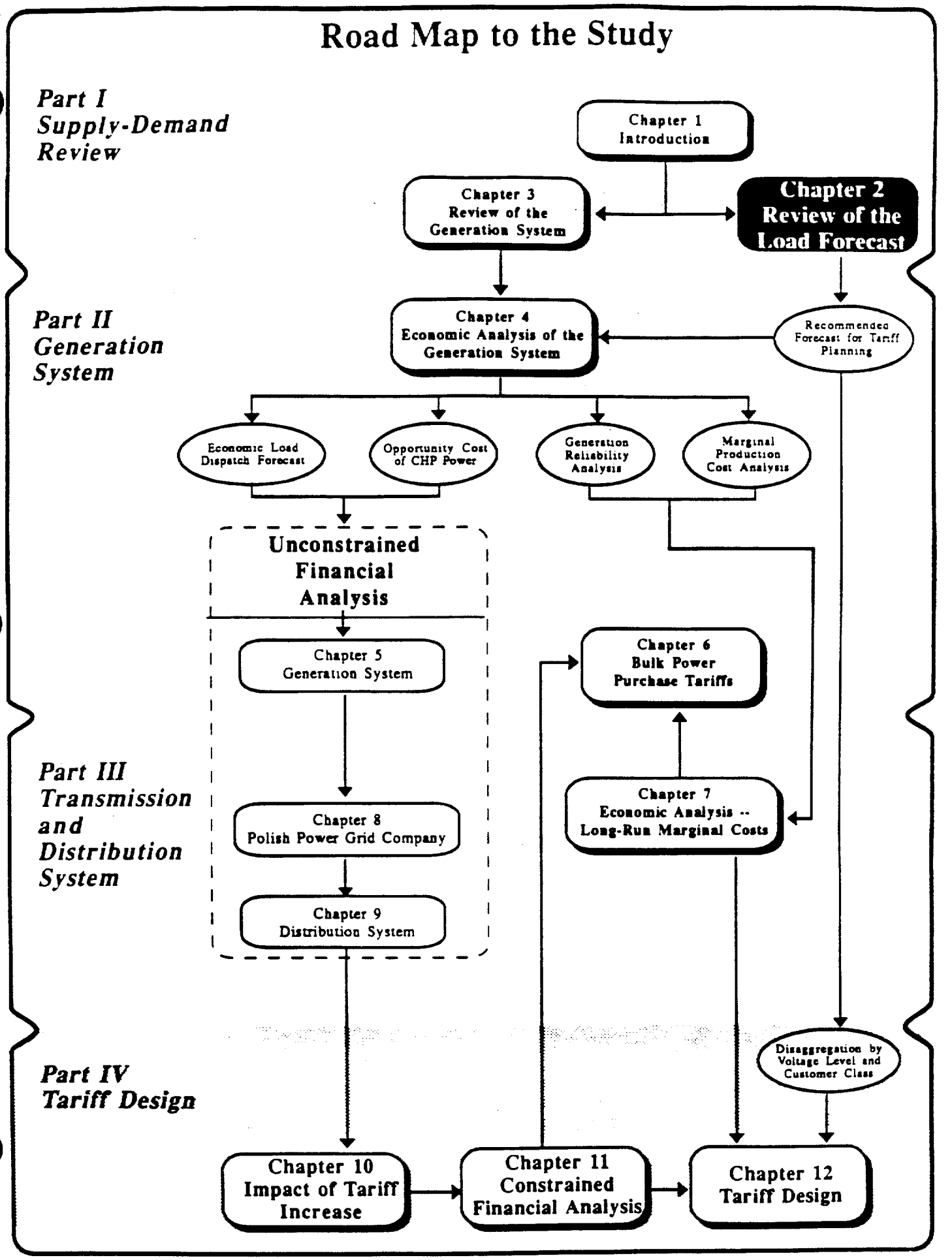
*Part III: Transmission and Distribution System.* This part of the report brings the results of Part II all the way down to the final consumer by first considering the structure of marginal costs at the transmission and distribution level, in Chapter 7. The financial analysis is separated into two chapters. Chapter 8 deals with the revenue requirements of the Polish Power Grid Company and Chapter 9 with the revenue requirements of distribution companies. Again, these forecasts of revenue requirements do not yet include any external considerations and are therefore called "unconstrained financial forecasts."

*Part IV: Tariff Design.* In Chapter 10 the impact of electricity prices is reviewed both with respect to different economic activities and with respect to the impact on the standard of

living in Poland. The results are incorporated in Chapter 11, where new financial forecasts are developed based on the analyses carried out in Chapters 5, 8 and 9, but this time adjusted by different scenarios of limitations on the extent of tariff increases and limitations on the extent and schedule of asset revaluation. From Chapter 11 emerges a "most likely" forecast of revenue requirements which is then used in Chapter 12 for the detailed tariff design.

This process is shown schematically in the road map that appears at the beginning of this chapter. To guide the reader through this complex process, the exhibit is repeated at the beginning of each chapter, showing the position of the subject matter being discussed and its relation to the rest of the study.

# Road Map to the Study



mapping forecast sales by voltage. To approximate the disaggregation, we first calculated the historical percentage share of final sales occurring at each voltage. The shares at each voltage for the year 1991 were then applied to future years to disaggregate final sales over the entire study period.

This assumption of constant consumption shares by voltage level is a simplification. The gradual movement of the economy from heavy industry toward services is not captured. Given limited historical data and probable discontinuities between historical and future trends, however, we concluded that forecasting trends would be less reliable (and the bias less clear) than the constant share assumption.

Exhibit 2-8 presents the base case load forecast disaggregated by voltage level and customer class.

Exhibit 2–1: **Basic Economic Data**

| Year | Real GDP (bn Zl 1987) | Population (million) | GDP/Capita (tysZl 1987) |
|---|---|---|---|
| 1980 | 15856 | 35.58 | 446 |
| 1981 | 14274 | 35.90 | 398 |
| 1982 | 13595 | 36.23 | 375 |
| 1983 | 14350 | 36.57 | 392 |
| 1984 | 15161 | 36.91 | 411 |
| 1985 | 15941 | 37.20 | 429 |
| 1986 | 16614 | 37.46 | 444 |
| 1987 | 16940 | 37.66 | 450 |
| 1988 | 17635 | 37.86 | 466 |
| 1989 | 17722 | 37.85 | 468 |
| 1990 | 15667 | 38.18 | 410 |
| 1991 | 14413 | 38.29 | 376 |
| Average Rates of Growth: | | | |
| 1980–91 | –0.9% | 0.7% | –1.5% |
| 1980–85 | 0.1% | 0.9% | –0.8% |
| 1985–89 | 2.7% | 0.4% | 2.2% |
| 1989–91 | –9.8% | 0.6% | –10.3% |

Source: These series were derived from:

1) From IBRD, World Tables
2) From International Monetary Fund, "International Financial Statistics"
3) From World Economy Research Institute of the Warsaw School of Economics, "Poland International Economic Report 1991/92

1989, however, the economy contracted dramatically, and has averaged minus 10 percent annual real growth for the past two years. The degree to which the historical data series accurately incorporates the emerging private sector, or otherwise captures real growth in periods of dramatic inflation, is not known.

This disturbing performance is not unexpected in light of Poland's historic redirection from a centrally planned toward a free market economy, which began in January 1990. Immediate "shocks" included complete price liberalization, the opening of borders to foreign trade, and a sharp exchange rate devaluation. Further, the demise of the CMEA resulted in the disruption of historical trading relationships, including the loss of relatively low-cost Soviet energy supplies. Economic adjustments within Poland over the last two years have resulted in:

- a steep decline in real wages as a result of a stringent anti-inflation program, and a consequent drop in domestic expenditures
- a high and rising level of government expenditure that has outpaced growth in revenues
- a state-owned enterprise system (SOE) that has failed to adapt to new realities, and in many cases clings to its inefficiencies at great cost to the government and the banking sector, despite falling productivity
- a private sector that has increased its participation in the economy dramatically, but a privatization process that remains slow and cumbersome.

While these problems are not intractable in the long term, the pace of transition to a stable market economy is unknown and the experience of other countries can provide very little guidance.

### Recent Electric Sales Data

Exhibit 2-2 reports historical sales and generation data for selected years from 1980 through 1991. Generally, sales growth has mirrored the economy, with steady increases in the 1985-1989 period, and dramatically decreasing generation and consumption from 1989 to 1991. An exception to the declining trend is the communal sector (combined residential, farm, and commercial sales), in which modest growth was maintained during the recent slowdown.

Exhibit 2 - 2

**Republic of Poland: Historical Generation and Consumption (GWh)**

| | 1980 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | Average Annual Rate (%) 1980 - 85 | 1985 - 89 | 1989 - 91 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **PUBLIC POWER SYSTEM** | | | | | | | | | | | |
| Industry | 59796 | 61858 | 63779 | 66012 | 67135 | 65402 | 57312 | 51052 | 0.7% | 1.4% | -11.6% |
| Traction | 4820 | 5478 | 5627 | 5834 | 6005 | 5875 | 5346 | 4915 | 2.6% | 1.8% | -8.5% |
| Communal | 26153 | 32789 | 34546 | 37132 | 38438 | 39792 | 39851 | 40417 | 4.6% | 5.0% | 0.8% |
| Final Domestic Sales | 90769 | 100125 | 103952 | 108978 | 111578 | 111069 | 102509 | 96384 | 2.0% | 2.6% | -6.8% |
| Exports | 4396 | 7568 | 7796 | 8703 | 7980 | 10268 | 11477 | 9326 | 11.5% | 7.9% | -4.7% |
| Imports (-) | 4161 | 5456 | 7833 | 10422 | 12456 | 12059 | 10437 | 6708 | 5.6% | 21.9% | -25.4% |
| TOTAL SALES | 91004 | 102237 | 103915 | 107259 | 107102 | 109278 | 103549 | 99002 | 2.4% | 1.7% | -4.8% |
| Network Losses | 12202 | 13337 | 13812 | 15448 | 14190 | 13345 | 11364 | 14369 | 1.8% | 0.0% | 3.8% |
| % of incoming | 11.8% | 11.3% | 11.7% | 12.6% | 11.7% | 10.9% | 9.9% | 12.7% | | | |
| Pumping in Hydro Plants | 1246 | 2797 | 3059 | 3275 | 3307 | 2922 | 2614 | 2747 | 17.6% | 1.1% | -3.0% |
| Self - Producer Supply to Grid (-) | 835 | 583 | 524 | 311 | 307 | 396 | 495 | 339 | -6.9% | -9.2% | -7.5% |
| NET GENERATION | 103617 | 117788 | 120262 | 125671 | 124292 | 125149 | 117032 | 115779 | 2.6% | 1.5% | -3.8% |
| Heat Generation Auxiliary Use | - | 2049 | 2027 | 2141 | 2045 | 2031 | 2050 | 2105 | - | -0.2% | 1.8% |
| Station Use | 7914 | 9053 | 9299 | 9600 | 9596 | 9725 | 9132 | 8961 | 2.7% | 1.8% | -4.0% |
| % of incoming | 7.1% | 7.1% | 7.2% | 7.1% | 7.2% | 7.2% | 7.2% | 7.2% | | | |
| GROSS GENERATION (GWh) | 111531 | 128890 | 131588 | 137412 | 135933 | 136905 | 128214 | 126845 | 2.9% | 1.5% | -3.7% |
| Load Factor | | | | | | | | | | | |
| MAXIMUM DEMAND (MW) | | | | | | | | | | | |
| **OTHER PRODUCERS** | | | | | | | | | | | |
| Self - Producer Factory Use | 8884 | 7741 | 7695 | 7646 | 7635 | 7681 | 7170 | 7051 | -2.7% | 0.2% | -4.2% |
| Self - Producer Supply to Grid | 835 | 583 | 524 | 311 | 307 | 396 | 495 | 339 | -6.9% | -9.2% | -7.5% |
| Other Supply to Grid | 36 | 34 | 34 | 35 | 31 | 28 | 27 | 29 | -1.1% | -4.7% | 1.8% |
| NET GENERATION | 9755 | 8358 | 8253 | 7992 | 7973 | 8105 | 7692 | 7419 | -3.0% | -0.8% | -4.3% |
| Station Use | 585 | 459 | 453 | 427 | 434 | 458 | 459 | 432 | -4.7% | -0.1% | -2.9% |
| % of incoming | 5.7% | 5.2% | 5.2% | 5.1% | 5.2% | 5.3% | 5.6% | 5.5% | | | |
| GROSS GENERATION (GWh) | 10340 | 8817 | 8706 | 8419 | 8407 | 8563 | 8151 | 7851 | -3.1% | -0.7% | -4.2% |
| Load Factor | | | | | | | | | | | |
| MAXIMUM DEMAND (MW) | | | | | | | | | | | |
| TOTAL GROSS GENERATION | 121871 | 137707 | 140294 | 145831 | 144340 | 145468 | 136365 | 134696 | 2.5% | 1.4% | -3.8% |

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Exhibit 2-3 further highlights trends by customer class. It is apparent that the industry sector has experienced the most dramatic reduction in consumption. Overall, its share of total sales declined from 67 percent (1980) to 53 percent (1991). Moreover, this structural change appears to have been gradual, and not merely a response to the adjustments of the past two years.[1]

In contrast, the consumption share of the communal sector has been steadily rising. Most notably, residential sales experienced rapid growth prior to 1989, and have even reported a modest increase in the last two years. Residential sales' share of total sales rose from 12 percent (1980) to 22 percent (1991).

### Impact of the Forecast on Tariff Planning

In an environment of considerable planning uncertainty, we believe that forecasts for rate-making should be conservative. In practice, financial revenue requirements determine the level of tariffs, while economic costs determine their structure. The financial revenue requirement (Zl/kWh) is defined as total annual costs (i.e., recovery of capital costs, O&M costs, self-financing requirements, and rate of return) divided by total sales. If expected sales are overestimated, the average revenue requirement will be understated. Given today's climate of uncertainty, a conservative (lower) forecast is prudent. If the forecast proves too conservative, over-recovery of revenue can be easily corrected by delaying the need for future tariff increases.

Because tariffs are set only for a year or two in advance, identifying the *structure* of the load -- by voltage level and customer class -- is as important as the precise level of total energy and capacity sales.

## 2.2 REVIEW OF EXISTING FORECASTS

We are aware of three different forecasting studies developed in Poland since 1990. These were prepared by:

- The Polish Academy of Sciences (PAS)

[1] The dramatic fall in low voltage (LV) industrial consumption in 1991 appears to be the result of a reclassification of some LV customers to LV commercial rather than to a total collapse of small industrial demand. We have therefore grouped these sales with commercial sales for the purposes of this analysis.

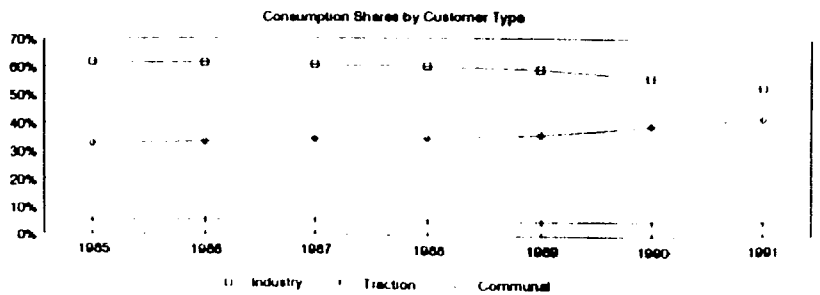
Exhibit 2 3

**Republic of Poland: Historical Sales and Consumption Shares by Customer Class (GWh)**

| | | 1980 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | Average Annual Rate (%) 1980 - 85 | 1985 - 89 | 1989 - 91 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INDUSTRY | HV | - | 34805 | 36209 | 37680 | 38531 | 37395 | 32761 | 29656 | - | 1.8% | -10.9% |
| | MV | - | 23482 | 23781 | 24220 | 24271 | 23558 | 20593 | 18848 | - | 0.1% | -10.6% |
| | LV | - | 3570 | 3788 | 4113 | 4333 | 4449 | 3959 | 2548 | - | 5.7% | -24.3% |
| | Total | 59796 | 61858 | 63779 | 66012 | 67135 | 65402 | 57312 | 51052 | 0.7% | 1.4% | -11.6% |
| TRACTION 1/ | HV | - | 164 | 169 | 175 | 180 | 176 | 160 | 147 | - | - | - |
| | MV | - | 5314 | 5458 | 5659 | 5825 | 5699 | 5186 | 4768 | - | - | |
| | Total | 4820 | 5478 | 5627 | 5834 | 6005 | 5875 | 5346 | 4915 | 2.6% | 1.8% | -8.5% |
| STREET LIGHTS | LV | 670 | 1274 | 1283 | 1186 | 1355 | 1506 | 1325 | 1372 | 13.7% | 4.3% | 4.6% |
| COMMERCIAL | MV | - | 927 | 999 | 1121 | 1185 | 1225 | 1179 | 1233 | | 7.2% | 0.3% |
| | LV | - | 7235 | 7640 | 7953 | 7997 | 8161 | 7039 | 8588 | | 3.1% | 2.6% |
| | Total | 7645 | 8162 | 8639 | 9074 | 9182 | 9386 | 8218 | 9821 | 1.3% | 3.6% | 2.3% |
| FARMS | MV | - | 599 | 654 | 728 | 754 | 745 | 711 | 682 | | 5.6% | -4.3% |
| | LV | - | 6629 | 7076 | 7726 | 7829 | 7888 | 7414 | 7712 | | 4.4% | -1.1% |
| | Total | 5360 | 7229 | 7731 | 8454 | 8582 | 8633 | 8124 | 8394 | 6.2% | 4.5% | -1.4% |
| RESIDENTIAL | LV | 11010 | 16126 | 16894 | 18417 | 19319 | 20267 | 22183 | 20829 | 7.9% | 5.9% | 1.4% |
| | | 84481 | 99962 | 103783 | 108803 | 111398 | 110893 | 102348 | 96236 | 3.4% | 2.6% | 6.8% |
| TOTAL FINAL SALES | | 89301 | 100126 | 103952 | 108978 | 111578 | 111069 | 102509 | 96384 | 2.3% | 2.6% | 6.8% |
| | HV | - | 34970 | 36209 | 37680 | 38531 | 37395 | 32761 | 29656 | - | 1.7% | -10.9% |
| | MV | - | 30321 | 30893 | 31728 | 32035 | 31227 | 27668 | 25531 | - | 0.7% | -9.6% |
| | LV | - | 34835 | 36681 | 39396 | 40832 | 42271 | 41920 | 41049 | - | 5.0% | -1.5% |

**CONSUMPTION SHARES OF TOTAL SALES**

| | 1980 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 |
|---|---|---|---|---|---|---|---|---|
| INDUSTRY | 0.67 | 0.62 | 0.61 | 0.61 | 0.60 | 0.59 | 0.56 | 0.53 |
| TRACTION | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 |
| COMMUNAL | 0.28 | 0.33 | 0.33 | 0.34 | 0.34 | 0.36 | 0.39 | 0.42 |
| Street Lights | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Commercial | 0.09 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.10 |
| Farms | 0.06 | 0.07 | 0.07 | 0.08 | 0.08 | 0.08 | 0.08 | 0.09 |
| Residential | 0.12 | 0.16 | 0.16 | 0.17 | 0.17 | 0.18 | 0.22 | 0.22 |
| TOTAL | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |



- The Polish Power Grid Company (PPGC), Department of Development
- The Ministry of Industry (MOI) as published by the OECD/IEA.

Each of these forecasts includes its own high and low scenario, for a total of six forecasts. The projections are all based on econometric studies, and are distinguished by different underlying assumptions about future economic growth rates in Poland. A general description of each study is presented in Appendix 2.1.

Based on our review of these forecasts and their underlying economic assumptions, we have defined three "scenarios" that broadly bracket possible future economic conditions:

Scenario 1: Optimistic Growth
Scenario 2: Rapid Recovery to Steady Growth
Scenario 3: Slow Recovery to Steady Growth.

For our analysis, the high scenarios from the PAS and PPGC studies, and the medium scenario from the MOI forecast[2] can be grouped as representative of Scenario 1 (Optimistic Growth). These forecasts all assume fairly rapid average real economic growth over the next decade. Similarly, the low scenarios from all three studies are representative of Scenario 2 (Rapid Recovery to Steady Growth). These forecasts assume slow or negative economic growth in the near term with rapid recovery to steady, stable growth thereafter. The underlying macroeconomic assumptions for these two scenarios are compared in Exhibit 2-4.

Based upon our review, we concluded that existing forecasts do not adequately consider Scenario 3. We therefore developed our own forecast for this scenario. This forecast, described in Appendix 2.2, projects end-use consumption trends; it is more conservative than Scenarios 1 and 2.

The individual forecasts reviewed within each scenario are compared briefly in the following paragraphs. Exhibit 2-5 compares their respective projections of total domestic generation requirements, adjusted to base year 1991.

[2] The Ministry of Industry also prepared a High macroeconomic case, but it was deemed unrealistic in the analysis, and an associated electricity demand forecast was not developed.

Exhibit 2–4
Summary of Macroeconomic Assumptions by Scenario

SCENARIO 1: Optimistic Growth

| | Economic Growth Rate (% per year) | | Apartment Construction (units per year) | |
|---|---|---|---|---|
| | PAS/PSE | MOI | PAS/PSE | MOI |
| 1990–95 | 3.2% | 5.1% | 200,000 | 170,000 |
| 1995–00 | 5.5% | 5.1% | – | 200,000 |
| 2000–05 | 4.1% | 4.9% | – | 230,000 |
| 2005–10 | 4.1% | 4.9% | – | 260,000 |
| 2010–20 | 3.7% | – | 350,000 | – |

**SCENARIO 2: Rapid Recovery to Steady Growth**

| | Economic Growth Rate (% per year) | | Apartment Construction (units per year) | |
|---|---|---|---|---|
| | PAS/PSE | MOI | PAS/PSE | MOI |
| 1990–95 | –1.0% | 3.4% | 130,000 | 125,000 |
| 1995–00 | 2.6% | 3.4% | – | 175,000 |
| 2000–05 | 3.2% | 2.6% | – | 210,000 |
| 2005–10 | 3.2% | 2.6% | – | 215,000 |
| 2010–20 | 3.4% | – | 220,000 | – |

Notes: (1) Scenario 1 includes "High" PAS/PSE and "Medium" MOI assumptions.
(2) Straight line growth assumed when interim year data not available.

Exhibit 2–5
Comparison of Forecasts of Gross Domestic Generation Requirements

SCENARIO 1: Optimistic Economic Growth

| | PAS High | | PSE High (Variant II) | | MOI Variant II | |
|---|---|---|---|---|---|---|
| year | TWh | % | TWh | % | TWh | % |
| 1991 | 132.0 | – | 132.0 | – | 132.0 | – |
| 1996 | 156.7 | 3.5% | 155.4 | 3.3% | 158.4 | 3.7% |
| 2001 | 187.9 | 3.7% | 179.4 | 2.9% | 189.2 | 3.6% |

SCENARIO 2: Rapid Recovery to Steady Economic Growth

| | PAS Low | | PSE Low (Variant I) | | MOI Variant I | |
|---|---|---|---|---|---|---|
| year | TWh | % | TWh | % | TWh | % |
| 1991 | 132.0 | – | 132.0 | – | 132.0 | – |
| 1996 | 142.1 | 1.5% | 141.5 | 1.4% | 150.8 | 2.7% |
| 2001 | 160.0 | 2.4% | 160.1 | 2.5% | 173.1 | 2.8% |

SCENARIOS 3: Slow Recovery to Steady Growth

| | End–Use Trends | |
|---|---|---|
| year | TWh | % |
| 1991 | 132.0 | – |
| 1996 | 129.9 | –0.3% |
| 2001 | 157.1 | 3.9% |

Notes:
(1) All forecasts have been adjusted to base year 1991.
(2) Forecast domestic generation requirements (TWh) for Scenarios 1 and 2 have been estimated from periodic growth rates for the forecasts shown in Exhibits presented in Appendix 1.1.

### Scenario 1: Optimistic Growth

Economic growth assumptions are shown in Exhibit 2-4. The PAS/PPGC forecasts assume slightly moderated economic growth averaging 3.2 percent annually from 1990 to 1995, rising to 5.5 percent over the next five years. The MOI forecast posits an average annual growth rate of 5.1 percent until 2000. It is not possible to compare economic growth assumptions for specific years because the MOI did not report interim-year assumptions.

Exhibit 2-5 compares the electricity requirements forecasts (adjusted to base year 1991) resulting from optimistic economic growth assumptions. Each forecast assumes that electricity requirements will grow in the range of 3.0 to 3.8 percent annually until the year 2000. The PAS and MOI studies imply an income elasticity of about 0.70, while the more recent PPGC study assumes the achievement of even greater energy efficiency, with a 0.55 elasticity. The PPGC forecast is lower, probably because it was prepared more recently than the other two. The difference in average annual growth rate after 10 years is about 0.5 percent.

### Scenario 2: Rapid Recovery to Steady Growth

The PAS and PPGC low forecasts assume "saucer-like" macroeconomic performance, i.e., negative growth in the near term followed by recovery. But the period of adjustment to the new economic order is rapid, with negative growth in 1991 and 1992 being followed by accelerated 7 percent real economic growth until 1995. (MOI probably made a similar assumption, although values assumed for interim years are not available.) After 1995, each forecast assumes 3 percent real growth (+/-0.4 percent).

Income elasticities in the early years are unstable. From 1995 to 2000, the PAS and PPGC studies assume income elasticities in the range of 0.90 to 1.0, falling to 0.7 or 0.8 thereafter. The MOI study results imply a dramatic increase in the energy intensity of the economy, a result that we cannot explain.

As shown in Exhibit 2-5, after energy requirements forecasts are adjusted to base year 1991, they fall within a narrow band, with the earlier MOI forecast being slightly higher than the PAS/PPGC results.

**Scenario 3: Slow Recovery**

Our independent forecast based on end-use trends is presented in Appendix 2.2 and summarized in Exhibit 2-5. Based on the experience of the recent past, the forecast projects slow electricity sales growth until 1996, with more rapid growth thereafter. Sales are forecast to reach the level of Scenario 2 (the PPGC "low" forecast) around the year 2001. This very conservative forecast characterizes the potential electricity requirements under a slow economic recovery scenario.

## 2.3 RECOMMENDED FORECAST FOR TARIFF PLANNING

Exhibit 2-6 compares the electricity demand forecasts discussed in Section 2.2. (For this exhibit, the PPGC "high" and "low" forecasts were chosen as representative of Scenarios 1 and 2, respectively.) Shown graphically, the three forecasts (Scenarios 1, 2, and 3) bracket demand under optimistic, stable, and more pessimistic views of future economic conditions in Poland.

We recommend that Scenario 2 (the PPGC Variant I "low" forecast) be applied for tariff planning. This forecast is the most recent forecast (December 1991) reviewed, and it also projects the lowest average annual growth in energy demand of all forecasts prepared in Poland. This base case forecast is shown in Exhibit 2-7.

## 2.4 DISAGGREGATION OF THE LOAD FORECAST BY VOLTAGE LEVEL AND CUSTOMER CLASS

For the long-run marginal cost analysis, it is necessary to disaggregate the recommended load forecast by voltage level and by customer class. Following PPGC convention, we have allocated final sales by the following distinct service voltage levels:

| | |
|---|---|
| VHV | 220 kV and above |
| HV | 61 to 220 kV |
| MV | 1 to 60 kV |
| LV | below 1 kV. |

The base case forecast (Scenario 2) was prepared by PPGC as a "top down" projection of total national energy demand rather than as a projection of final sales by customer category (e.g., residential, commercial, industrial) or tariff class. Thus, there is no clear basis for

Exhibit 2 6
Comparison of Generation Requirements Forecasts (GWh)

| | Actual 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | Rate of Growth 1991 - 96 | Rate of Growth 1996 01 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **SCENARIO 1: OPTIMISTIC GROWTH** | | | | | | | | | | | | | |
| PSE Variant II (High) | 134696 | 137200 | 142700 | 148300 | 154200 | 157377 | 161854 | 167900 | 173309 | 176400 | 179993 | 3.2% | 2.7% |
| growth rate (%) | | 1.9% | 4.0% | 3.9% | 4.0% | 2.1% | 2.8% | 3.7% | 3.2% | 1.8% | 2.0% | | |
| **SCENARIO 2: RAPID RECOVERY TO STEADY GROWTH** | | | | | | | | | | | | | |
| PSE Variant I (Low) | 134696 | 133200 | 135200 | 137800 | 141300 | 143400 | 147000 | 150700 | 154400 | 158300 | 156400 | 1.3% | 1.8% |
| growth rate (%) | | -1.1% | 1.5% | 1.9% | 2.5% | 1.5% | 2.5% | 2.5% | 2.5% | 2.5% | -1.2% | | |
| **SCENARIO: SLOW RECOVERY AND SLOW GROWTH** | | | | | | | | | | | | | |
| End - Use Trends | 134696 | 132459 | 130619 | 129593 | 132253 | 131776 | 136510 | 142721 | 148511 | 154071 | 157107 | -0.4% | 3.6% |
| growth rate (%) | | -1.7% | -1.4% | -0.8% | 2.1% | -0.4% | 3.6% | 4.6% | 4.1% | 3.7% | 2.0% | | |

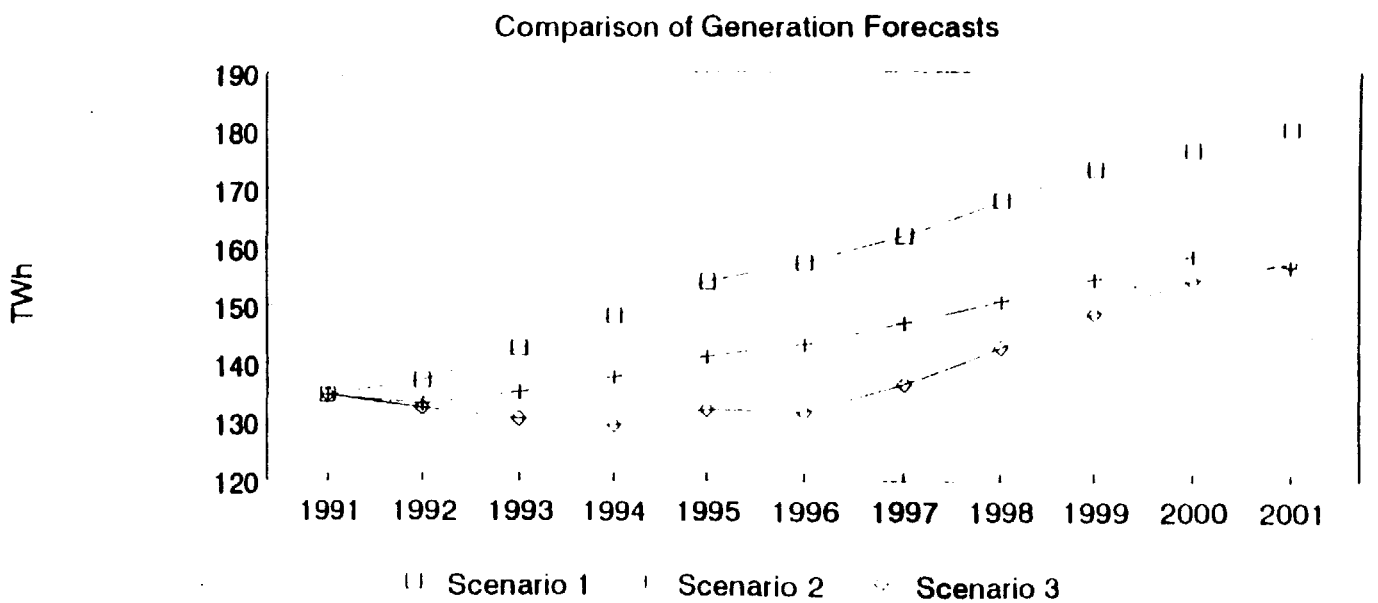


Exhibit 2 - 7: Base Case Forecast

Republic of Poland: PSE "Low" Forecast Generation and Consumption (GWh)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | Avg Annual Rate (%) 1991 - 96 | Avg Annual Rate (%) 1996 - 01 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **PUBLIC POWER SYSTEM** | | | | | | | | | | | | |
| Industry | 48968 | 48864 | 48843 | 49300 | 50419 | 51630 | 52372 | 53355 | 54900 | 54673 | -0.2% | 1.6% |
| Traction | 5160 | 5631 | 6158 | 6800 | 6941 | 7094 | 7182 | 7303 | 7500 | 7508 | 7.1% | 1.6% |
| Communal | 40926 | 43079 | 45440 | 48400 | 49878 | 51470 | 52610 | 54009 | 56000 | 56031 | 4.3% | 2.4% |
| Final Domestic Sales | 95073 | 97574 | 100441 | 104500 | 107238 | 110194 | 112165 | 114666 | 118400 | 118212 | 2.2% | 2.0% |
| Exports 1/ | 3200 | 3200 | 3300 | 3300 | 1900 | 1900 | 1900 | 1900 | 1900 | 0 | - | - |
| Imports (-) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - | - |
| TOTAL SALES | 98273 | 100774 | 103741 | 107800 | 109138 | 112094 | 114065 | 116566 | 120300 | 118212 | 2.0% | 1.6% |
| Network Losses | 13489 | 12796 | 12194 | 11500 | 11908 | 12256 | 12614 | 12974 | 13000 | 13135 | -3.7% | 2.0% |
| % of incoming | 11.84% | 11.05% | 10.32% | 9.6% | 9.66% | 9.68% | 9.71% | 9.73% | 9.8% | 9.72% | | |
| Pumping in Hydro Plants 2/ | 2600 | 2600 | 2600 | 2600 | 2600 | 2600 | 3667 | 4200 | 4200 | 4200 | -1.1% | 10.1% |
| Self - Producer Supply to Grid (-) | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 3.4% | 0.0% |
| NET GENERATION | 113962 | 115771 | 118136 | 121500 | 123246 | 126550 | 129946 | 133340 | 137100 | 135147 | 1.3% | 1.9% |
| Heat Generation Auxiliary Use | 2152 | 2200 | 2250 | 2300 | 2339 | 2378 | 2418 | 2459 | 2500 | 2519 | 2.1% | 1.5% |
| Station Use | 8966 | 9129 | 9315 | 9400 | 9715 | 9972 | 10236 | 10501 | 10600 | 10634 | 1.6% | 1.8% |
| % of incoming | 7.18% | 7.18% | 7.18% | 7.18% | 7.18% | 7.18% | 7.18% | 7.18% | 7.18% | 7.17% | | |
| GROSS GENERATION (GWh) | 125100 | 127100 | 129700 | 133200 | 135300 | 138900 | 142600 | 146300 | 150200 | 148300 | 1.3% | 1.9% |
| Load Factor | 0.648 | 0.653 | 0.657 | 0.662 | 0.672 | 0.673 | 0.676 | 0.677 | 0.681 | 0.670 | | |
| MAXIMUM DEMAND (MW) | 22024 | 22224 | 22528 | 22978 | 22969 | 23570 | 24077 | 24660 | 25187 | 25260 | - | 1.9% |
| Load Growth (%) | | 0.91% | 1.37% | 2.00% | 0.05% | 2.53% | 2.15% | 2.42% | 2.14% | 0.29% | | |
| **OTHER PRODUCERS** | | | | | | | | | | | | |
| Self - Producer Factory Use | 7200 | 7200 | 7200 | 7200 | 7200 | 7200 | 7200 | 7200 | 7200 | 7200 | - | - |
| Self - Producer Supply to Grid | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | - | - |
| Other Supply to Grid | - | - | - | - | - | - | - | - | - | - | - | - |
| NET GENERATION | 7600 | 7600 | 7600 | 7600 | 7600 | 7600 | 7600 | 7600 | 7600 | 7600 | - | - |
| Station Use | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | - | - |
| % of incoming | 6.2% | 6.2% | 6.2% | 6.2% | 6.2% | 6.2% | 6.2% | 6.2% | 6.2% | 6.2% | | |
| GROSS GENERATION (GWh) | 8100 | 8100 | 8100 | 8100 | 8100 | 8100 | 8100 | 8100 | 8100 | 8100 | - | - |
| Load Factor | 0.648 | 0.653 | 0.657 | 0.662 | 0.672 | 0.673 | 0.676 | 0.677 | 0.681 | 0.670 | | |
| MAXIMUM DEMAND (MW) | 1426 | 1416 | 1407 | 1397 | 1376 | 1375 | 1368 | 1365 | 1358 | 1380 | - | 0.0% |
| TOTAL GROSS GENERATION 3/ | 133200 | 135200 | 137800 | 141300 | 143400 | 147000 | 150700 | 154400 | 158300 | 156400 | 1.3% | 1.8% |
| PSE Forecast 4/ | 133200 | 135200 | 137800 | 141300 | 143400 | 147000 | 150700 | 154400 | 158300 | 156400 | | |
| Correction Factor Used 5/ | 0.968 | 1.006 | 1.006 | 1.000 | 1.001 | 1.002 | 0.993 | 0.997 | 1.000 | 0.973 | | |
| TOTAL MAXIMUM DEMAND (PSE) 6/ | 23450 | 23640 | 23935 | 24375 | 24365 | 24945 | 25445 | 26025 | 26545 | 26640 | - | 1.8% |
| Annual Load Factor 7/ | 0.648 | 0.653 | 0.657 | 0.662 | 0.672 | 0.673 | 0.676 | 0.677 | 0.681 | 0.670 | | |

1/ Includes 300 GWh "fee" for transit. No exports assumed after 2000.
2/ Miloty pumping is included; this load is estimated as 1067 GWh by 1996 and another 533 GWh by 1999.
3/ Includes domestic requirements plus international energy exchange estimated by PSE.
4/ PSE estimate adjusted to include international energy exchange and Miloty hydro pumping; also excludes 100 GWh unserved energy assumed by PSE after 1994.
5/ This correction factor used to scale the non - fixed items in the disaggregated sales and generation forecast to achieve the PSE total gross generation forecast.
6/ Domestic maximum demand estimated by PSE, including demand related to international energy exchange.
7/ Derived from maximum demand (PSE) and total gross generation (PSE forecast adjusted as noted in 4/ above).

mapping forecast sales by voltage. To approximate the disaggregation, we first calculated the historical percentage share of final sales occurring at each voltage. The shares at each voltage for the year 1991 were then applied to future years to disaggregate final sales over the entire study period.

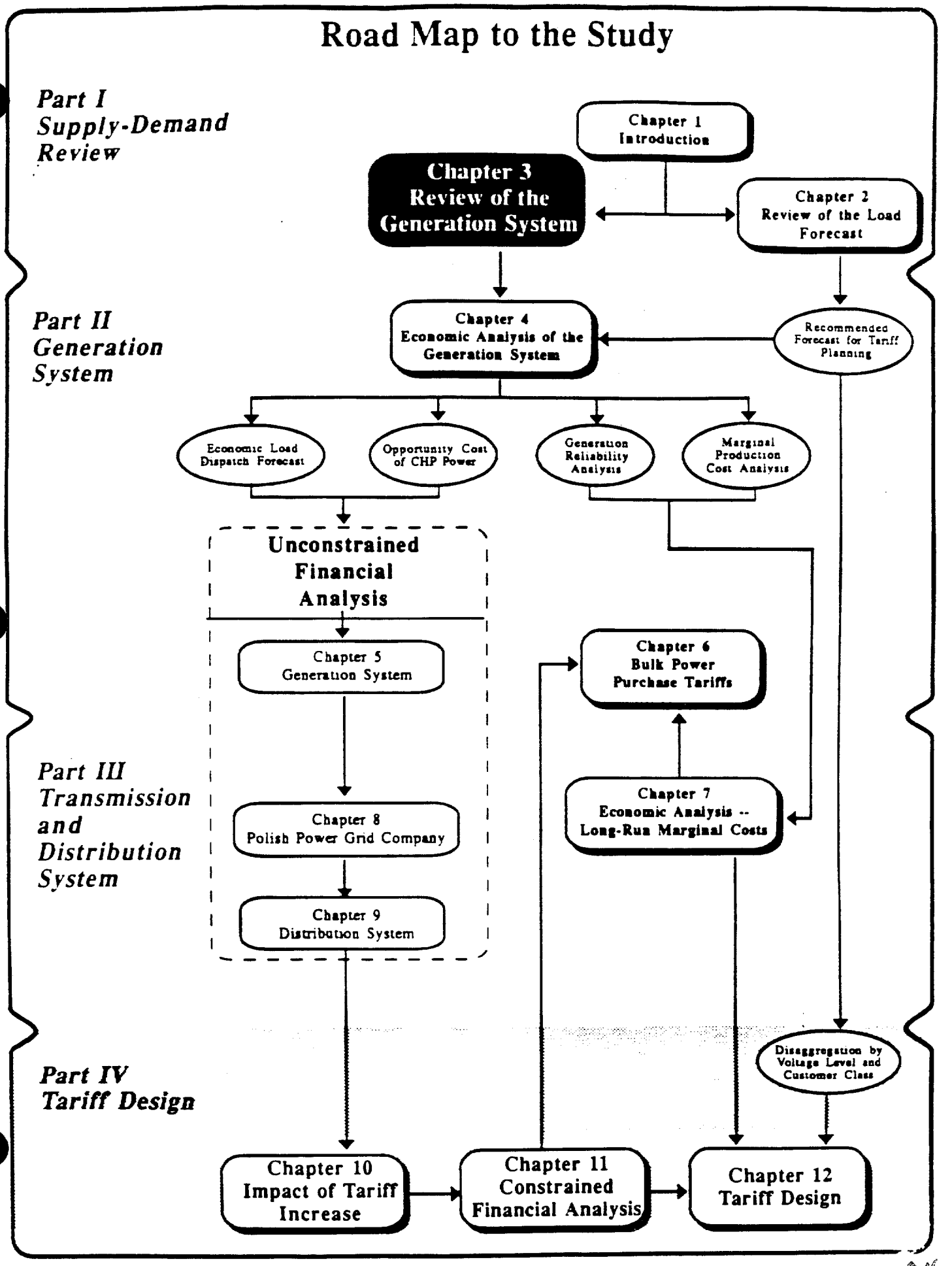
This assumption of constant consumption shares by voltage level is a simplification. The gradual movement of the economy from heavy industry toward services is not captured. Given limited historical data and probable discontinuities between historical and future trends, however, we concluded that forecasting trends would be less reliable (and the bias less clear) than the constant share assumption.

Exhibit 2-8 presents the base case load forecast disaggregated by voltage level and customer class.

**Exhibit 2 - 8: Base Case Forecast**
**Republic of Poland: PSE "Low" Forecast of Sales by Customer Class (GWh)**

| | | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | Avg Annual Rate (%) 1991-96 | Avg Annual Rate (%) 1996-01 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INDUSTRY | HV | 28229 | 28158 | 28146 | 28410 | 29054 | 29752 | 30180 | 30746 | 31637 | 31506 | -0.4% | 1.6% |
| | MV | 17844 | 17799 | 17791 | 17958 | 18365 | 18807 | 19077 | 19435 | 19998 | 19915 | -0.5% | 1.6% |
| | LV | 2914 | 2907 | 2906 | 2933 | 2999 | 3071 | 3116 | 3174 | 3266 | 3252 | 3.3% | 1.6% |
| | Total | 48988 | 48864 | 48843 | 49300 | 50419 | 51630 | 52372 | 53355 | 54900 | 54673 | -0.2% | 1.6% |
| TRACTION 1/ | HV | 155 | 169 | 185 | 204 | 208 | 213 | 215 | 219 | 225 | 225 | - | - |
| | MV | 5005 | 5462 | 5973 | 6596 | 6733 | 6881 | 6967 | 7084 | 7275 | 7283 | - | - |
| | Total | 5160 | 5631 | 6158 | 6800 | 6941 | 7094 | 7182 | 7303 | 7500 | 7508 | 7.1% | 1.6% |
| STREET LIGHTS | LV | 1375 | 1448 | 1527 | 1627 | 1676 | 1730 | 1768 | 1815 | 1882 | 1883 | 4.1% | 2.4% |
| COMMERCIAL | MV | 1229 | 1294 | 1365 | 1454 | 1498 | 1546 | 1580 | 1622 | 1682 | 1683 | 4.0% | 2.4% |
| | LV | 7963 | 8382 | 8841 | 9417 | 9705 | 10015 | 10237 | 10509 | 10896 | 10902 | 2.5% | 2.4% |
| | Total | 9192 | 9676 | 10206 | 10871 | 11203 | 11560 | 11817 | 12131 | 12578 | 12585 | 2.7% | 2.4% |
| FARMS | MV | 710 | 747 | 788 | 840 | 865 | 893 | 913 | 937 | 971 | 972 | 4.9% | 2.4% |
| | LV | 7712 | 8117 | 8562 | 9120 | 9399 | 9698 | 9913 | 10177 | 10552 | 10558 | 4.0% | 2.4% |
| | Total | 8422 | 8865 | 9351 | 9960 | 10264 | 10591 | 10826 | 11114 | 11523 | 11530 | 4.1% | 2.4% |
| RESIDENTIAL | LV | 21937 | 23091 | 24356 | 25943 | 26735 | 27588 | 28200 | 28949 | 30017 | 30033 | 5.1% | 2.4% |
| TOTAL FINAL SALES | | 95073 | 97574 | 100441 | 104500 | 107238 | 110194 | 112165 | 114666 | 118400 | 118212 | 2.2% | 2.0% |
| | HV | 28384 | 28327 | 28331 | 28614 | 29262 | 29965 | 30395 | 30965 | 31862 | 31731 | -0.3% | 1.6% |
| | MV | 24788 | 25302 | 25917 | 26847 | 27461 | 28127 | 28536 | 29077 | 29926 | 29852 | 1.5% | 1.7% |
| | LV | 41901 | 43945 | 46193 | 49040 | 50515 | 52102 | 53233 | 54624 | 56613 | 56629 | 4.2% | 2.3% |

# Road Map to the Study



# CHAPTER 3: REVIEW OF THE GENERATION SYSTEM

## 3.1 OBJECTIVES AND APPROACH

The cost of generating power is the largest single component of the cost of power to the final consumer. This cost is the starting point for both determining a pricing structure based on marginal costs and computing financial revenue requirements.

This chapter examines the current and expected characteristics of power generation in Poland to help determine the major issues affecting the cost of power production. It also contains assumptions about the forecast of investments and operating costs for the medium term as a prelude to the economic and financial analysis of the generation system in Part II of this study.

This chapter first reviews the structure of the existing generating system in terms of power technologies and fuels. Next, it reviews the current development plans and comments on the adequacy of these plans in relation to the demand forecast scenario adopted for this study. Based on the adopted scenario of system development, a set of assumptions is presented with respect to the capital investments and operating costs that were used in the economic and financial analysis of the system. In connection with the adopted development forecast, comments are made on the assumed structure of the generation system and the recommended structure of transfer prices at the generation level.

## 3.2 EXISTING SYSTEM

### 3.2.1 The Polish Public Power System

The sources of energy in the Polish power system can be classified into three categories: the public system, autoproducers, and the international exchanges. Although the public power system is of primary concern in this tariff study, the contributions of autoproducers and international exchanges are discussed when relevant.

The generation component of the public power system consists of thermal and hydroelectric powerplants totalling approximately 29,600 MW of installed capacity. Exhibit 3-1 contains a summary of this system, showing that 93.2 percent of the installed capacity is in fossil-fired thermal plants and the rest in hydroelectric stations.

# SUMMARY OF THE PUBLIC GENERATION SYSTEM

## POLAND – SUMMARY OF THE PUBLIC GENERATION SYSTEM

| | PLANT NAME | TYPE | FUEL | MEAN UNIT CAPACITY MW | NO. UNITS | NAMEPLATE CAPACITY MW | PEAKING CAPABILITY MW | PERCENT OF SYSTEM CAPABILITY | ANNUAL OPERATING EXPENSES $/KW | FUEL TRANSPO COST $/MWH | 1991 PRODUCTION GWH | PERCENT OF GENERATION REQUIREMENTS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | BELCHATOW | GRID | LIGNITE | 360 | 12 | 4320 | 4320 | 15.4% | 11.27 | 0.00 | 27213 | 21.9% |
| 2 | PATNOW | GRID | LIGNITE | 200 | 10 | 2000 | 2000 | 7.1% | 12.36 | 0.00 | 7628 | 6.1% |
| 3 | TUROW | GRID | LIGNITE | 200 | 10 | 2000 | 2000 | 7.1% | 28.51 | 0.00 | 12035 | 9.7% |
| 4 | ADAMOW | GRID | LIGNITE | 120 | 5 | 600 | 480 | 1.7% | 33.90 | 0.00 | 2875 | 2.3% |
| 5 | KONIN | GRID | LIGNITE | 65 | 9 | 583 | 523 | 1.9% | 30.68 | 0.00 | 3148 | 2.5% |
| | LIGNITE FIRED PUBLIC PLANTS | | | | | 9503 | 9323 | 33.2% | | | 52899 | 42.6% |
| 6 | OSTROLEKA B | GRID | COAL | 200 | 3 | 600 | 600 | 2.1% | 20.38 | 1.91 | 2864 | 2.3% |
| 7 | KOZIENICE | GRID | COAL | 260 | 10 | 2600 | 2600 | 9.3% | 17.94 | 1.59 | 7996 | 6.4% |
| 8 | POLANIEC | GRID | COAL | 200 | 8 | 1600 | 1600 | 5.7% | 18.80 | 1.35 | 7173 | 5.8% |
| 9 | RYBNIK | GRID | COAL | 200 | 8 | 1600 | 1600 | 5.7% | 20.95 | 0.68 | 9252 | 7.5% |
| 10 | JAWORZNO III | GRID | COAL | 200 | 6 | 1200 | 1140 | 4.1% | 25.14 | 0.71 | 6302 | 5.1% |
| 11 | DOLNA ODRA | GRID | COAL | 200 | 8 | 1600 | 1600 | 5.7% | 17.42 | 2.09 | 6856 | 5.5% |
| 12 | LAZISKA | GRID | COAL | 173 | 6 | 1040 | 920 | 3.3% | 29.72 | 0.37 | 4286 | 3.5% |
| 13 | LAGISZA | GRID | COAL | 120 | 7 | 840 | 723 | 2.6% | 24.48 | 0.85 | 3423 | 2.8% |
| 14 | SIERSZA | GRID | COAL | 123 | 6 | 738 | 630 | 2.2% | 29.17 | 0.79 | 3128 | 2.5% |
| 15 | STALOWA WOLA | GRID | COAL | 64 | 6 | 384 | 345 | 1.2% | 18.61 | 1.47 | 1356 | 1.1% |
| | COAL FIRED FULLY DISPATCHABLE PLANTS | | | | | 12202 | 11758 | 41.9% | | | 52636 | 42.4% |
| | FULLY DISPATCHABLE GRID PLANTS | | | | | 21705 | 21081 | 75.2% | | | 105535 | 85.0% |
| 16 | SKAWINA | GRID-C | COAL | 79 | 7 | 550 | 495 | 1.8% | 21.07 | 1.14 | 1919 | 1.5% |
| 17 | JAWORZNO II | GRID-C | COAL | 50 | 7 | 350 | 300 | 1.1% | 22.79 | 0.87 | 904 | 0.7% |
| 18 | BLACHOWNIA | GRID-C | COAL | 47 | 6 | 282 | 244 | 0.9% | 25.60 | 1.79 | 781 | 0.6% |
| 19 | HALEMBA | GRID-C | COAL | 50 | 4 | 200 | 200 | 0.7% | 42.33 | 0.23 | 769 | 0.6% |
| 20 | JAWORZNO I | GRID-C | COAL | 29 | 5 | 145 | 93 | 0.3% | 26.97 | 0.91 | 279 | 0.2% |
| 21 | MIECHOWICE | GRID-C | COAL | 55 | 2 | 110 | 101 | 0.4% | 30.03 | 0.04 | 295 | 0.2% |
| 22 | POMORZANY | GRID-C | COAL | 60 | 2 | 120 | 112 | 0.4% | 42.88 | 3.73 | 401 | 0.3% |
| | COLLECTOR TYPE GRID PLANTS | | | | | 1757 | 1545 | 5.5% | | | 5348 | 4.3% |
| 23 | SIEKIERTY | CHP | COAL | 125 | 4 | 500 | 619 | 2.2% | 37.68 | 1.91 | 1794 | 1.4% |
| 24 | KRAKOW | CHP | COAL | 115 | 4 | 460 | 446 | 1.6% | 20.30 | 1.21 | 1791 | 1.4% |
| 25 | WROCLAW | CHP | COAL | 100 | 2 | 200 | 259 | 0.9% | 26.32 | 2.60 | 1089 | 0.9% |
| 26 | SMALLER CHP | CHP | COAL | 30 | 100 | 2621 | 2174 | 7.8% | 28.66 | 2.25 | 7895 | 6.4% |
| | COMBINED HEAT AND POWER PLANTS | | | | | 4160 | 3498 | 12.5% | | | 12569 | 10.1% |
| | PUBLIC THERMAL | | | | | 27622 | 26124 | 93.2% | | | 123452 | 99.5% |
| | PUBLIC HYDROELECTRIC | | | | | 2005 | 1918 | 6.8% | | | 646 | 0.5% |
| | TOTAL PUBLIC | | | | | 29627 | 28042 | 100.0% | | | 124098 | 100.0% |

### 3.2.2 Hydroelectric System

The hydroelectric component consists of three pumped storage plants, two conventional hydroelectric plants with some pumped storage capability, and several smaller run-of-river plants. While the contribution of hydro to meeting the daily peak loads is important, Poland's total net hydroelectric production is very small. The hydro system is virtually a mechanism for shifting loads during the day, thereby minimizing load fluctuations on the thermal system and maintaining primary control in the system.

### 3.2.3 Thermal System

There are 55 thermal generating plants in Poland. All of them consist of steam turbines burning primarily either lignite or hard coal, and many of these plants are also used in a cogeneration cycle to supply heat to local district heating networks. Thermal plants are classified into one of three categories depending in the extent of the cogeneration process and the steam path between boilers and generators. In this study, we refer to these three categories as conventional grid plants, collector grid plants, and combined heat and power (CHP) plants. English translations of Polish documents also refer to conventional grid plants as "professional" plants or "system" grid plants.

The classification above is relevant to the objectives of the electricity pricing study because there are important differences in the institutional, operational and economic aspects of each type of plant. Grid plants, both conventional and collector, can be considered to lie entirely within the power sub-sector, while CHP plants are shared between the power and heating sub-sectors.

#### Conventional Grid Plants

This category of thermal plants is by far the most important in terms of power production. Conventional grid plants have a conventional arrangement of blocks or units consisting of one boiler dedicated to its own specific turbine-generator set. Some units in conventional grid plants are connected to heating networks through the removal of steam from the low-pressure segment of the turbine. This is a very efficient link because it allows the utilization of heat that would otherwise be largely wasted in the condensing process.

The 15 conventional grid plants in Poland account for 85 percent of total energy production. Five of these plants -- Belchatow, Patnow, Turow, Adamow and Konin -- are the only plants

in the system fired with lignite or "brown coal" and are among the country's largest and most economic powerplants. Thus, while lignite plants contribute roughly one-third of total installed capacity, their production amounts to 42.6 percent of the total.

Unit sizes in conventional grid plants vary between less than 10 MW and 500 MW, but most of the generation is produced by units in the 100 MW to 360 MW range. About half the capacity is in 200 MW units, making this the most representative unit size in the system.

All lignite- and coal-fired units must use small amounts of residual oil or natural gas during startup and when operating at very low output. Two blocks (boiler-turbine-generator) of the ten blocks installed in Patnow are currently fuelled with No. 6 residual fuel oil or "mazout," but there are plans for converting these to burn lignite.

### Collector Grid Plants

There is no clear technical difference between a collector grid plant and a CHP plant. In both cases, the steam from several boilers is used partly for power and partly to maintain temperature and pressure in a district heating network. Also, some boilers may be exclusively dedicated to the heating network and some may be exclusively dedicated to power generation. In any case, many parts of these facilities are used for both purposes; thus, investments and operating costs are shared between the two products, power and heat.

From an institutional point of view, it is important to establish that the primary product of a collector plant is power, while the primary product of a CHP plant is heat. As such, collector plants would be expected to remain controlled by the power sub-sector through either ownership or regulatory authority, while CHP plants would be controlled by the heat sub-sector.

There are 7 collector grid plants in Poland. They are among the smallest, oldest and most expensive to operate of all grid plants. Therefore, these plants only contribute 4.3 percent of all energy produced in the country.

### CHP Plants

Combined heat and power plants (CHP) supply a substantial quantity of heat to district heating networks in comparison to the heat used to supply electricity to the grid.

Many CHP plants in Poland are built for district heating and only subsequently retro-fitted to produce power. This practice generally leads to a less-efficient design than if the plant is essentially using waste heat from power generation as discussed above in the conventional grid plants section. Furthermore, the resulting design limits the flexibility in dispatching power from CHP plants because their power can, in general, be economically produced only when there is demand for the associated heat.

Like collector grid plants, CHP plants are generally small with three notable exceptions: the Siekierty, Krakow and Wroclaw plants are fitted with units in the 100 MW range. As a group, CHP plants contribute 10.1 percent of power generation to the public system, heavily concentrated during the winter heating season.

### 3.2.4 Current Supply-Demand Balance

With a peak load of approximately 22,000 MW in 1992 and an installed capacity of 29,627 MW, the system currently has a nominal reserve margin of about 35 percent. In addition, up to 1,290 MW are available as surplus power from autoproducers, bringing the nominal reserve to over 40 percent. Eliminating non-firm resources such as auto-producer surplus and including deratings in the existing system brings the total firm reserve margin down to about 27.5 percent.

On a monthly basis, current reserve margin levels fluctuate between 15 and 40 percent due to the monthly variations in peak demand, CHP capacity, and the capacity undergoing planned maintenance. It appears possible to reduce the monthly fluctuation in reserve margin levels by alternative scheduling of planned maintenance. However, this is not necessary at present because minimum reserve levels provide adequate generation reliability at all times.

## 3.3 GENERATION SYSTEM DEVELOPMENT

### 3.3.1 Issues

#### Modernization

A generating system evolves through capacity additions, which are needed to meet increasing demand and to replace old units that are being retired as they become too inefficient, too unreliable, or too costly to maintain. Other changes in the system can take place as a result of one or a combination of the following:

- Repowering - the addition of capacity to an existing machine by changes in the turbine or generator.

- Redevelopment - changes in the power potential of an existing hydroelectric plant by modifications in water availability, reservoir storage or hydraulic head.

- Life extension - overhaul of older units to increase their reliability and efficiency, thus lowering their operating costs and delaying retirement.

- Fuel conversion - modifications to boiler and fuel supply facilities to take advantage of cheaper fuels or to achieve compliance with emission standards by burning cleaner fuels.

- Environmental control - the addition of emission controls and other facilities to render the plants in compliance with new environmental standards.

In most large systems, these additional changes are small. In Poland, the relatively low demand growth rate expected for the medium term and the introduction of tight environmental control standards are likely to make these changes, collectively called "modernizations," predominant over capacity additions.

Furthermore, programs for the expansion of CHP capacity are largely controlled by forecasts of heat demand growth, but include generation capacity associated with heat production. This further limits the need for additional capacity in system grid plants.

### Fuel Issues

Two critical issues affecting the cost of power in Poland are the availability of natural gas as an alternative to expensive emission controls and the future of coal and lignite prices.

Natural gas remains a strong alternative for the future. However, at present, it is difficult to make any firm forecasts of either its price or its availability to the power sector in the vast quantities necessary to displace lignite or coal as a baseload resource.

Poland's coal sector is in crisis. As many as half the nation's coal mines are facing potential shut down because production costs are higher than internal subsidized prices, and in some

cases, border prices. The lignite sector faces mounting environmental standards that threaten to reduce its margin of competitiveness.

#### Power Sector Restructuring Issues

Under Poland's current policy to liberalize the power sector, it is expected that its generating utilities will follow market (i.e., pricing) forces. Thus, tariff development can only rely on generation plans to the extent that these plans appear stable under economic pricing criteria. Regardless of tariff recommendations, it is the ability of the Polish economy to adjust to these economic pricing criteria that will ultimately determine whether rehabilitations can be made, whether fuels will be available, whether more CHP will be built and, above all, whether the demand will indeed grow as planned.

### 3.3.2 PPGC Generation Expansion Plan

In December 1991 the Polish Power Grid Company (PPGC) issued a report describing a plan for expanding the generation system. This analysis is now being updated through an ongoing study, but its results are not yet available. A major output of the current review is expected to be the economic ranking of modernization alternatives in the existing system. While this ranking is unlikely to constitute a firm plan of modernization under the decentralization policies, it is indeed possible that such a ranking will to some extent influence the ability of generating companies to secure financing to carry out those plans.

#### Adopted Scenario

At present, the 1991 analysis by PPGC constitutes the best available reference by which to forecast the medium-term evolution of the system. This analysis was carried out using the Wien Automatic System Planning Package (WASP) over four major scenarios. These scenarios consist of combinations of different load growth assumptions and different conditions of availability of natural gas as a fuel for power generation.

One of these scenarios (Scenario Ic) consists of a combination of low load growth and low availability of natural gas. This scenario was used as a working assumption for this study; minor changes were made to Scenario Ic to reflect the results of the review of the load forecast reported separately (Chapter 2), new information on the generation system obtained

during the data collection efforts, and small differences in modelling the contribution of different resources to meet the load.

### Comments to PPGC Expansion Plan

The following is a list of the major assumptions used in PPGC's scenario Ic regarding additions of new capacity and comments on the assumptions adopted in this study with respect to those same resources:

- PPGC assumed in 1991 that the Opole coal-fired power plant currently under construction will add 2,160 MW of capacity between 1992 and 1996. For this study, it has been assumed that the first full year of operation of the first 360 MW unit will be 1994 and that the plant will be completed by 1997.

- PPGC assumed that 350 MW of gas turbines (50 MW unit size) will be added between 1996 and 1998 without further additions until after 2000. For this study, it has been assumed that 300 MW of gas turbines (150 MW unit size) will be added in 1997 followed by one additional 150 MW unit in 2000.

- PPGC assumed that the Czorsztyn hydroelectric power plant (92 MW) will be added by 1995 and that the Mloty pumped storage hydroelectric project (750 MW) will be completed by 1999 followed by another pumped storage project, Roznow II, also of 750 MW. The assumption regarding the Mloty project was retained for the purposes of this study because it appears that this project, complemented with gas turbines, could provide much needed peak energy towards the end of the decade. Other hydroelectric projects were not included because they are not needed for capacity in the medium term.

- PPGC assumed that the CHP development plan, driven by demand from heat, will add 2,340 MW of electric capacity from these plants between now and 2000. This assumption was maintained, but the cost of this power is determined differently, as will be discussed later.

These assumptions refer only to those additions that could have an impact on or before 1997 in terms of operation costs or capital disbursements. PPGC's plan covers a much longer period (to 2010) and the assumptions over the long range are not directly relevant to this study. The only relevant addition in the long term is the first base load unit not belonging to

the already committed Opole project. This is a 370 MW lignite-fired unit (Belchatow II) in 2003. This assumption was retained for our study.

### 3.3.3 Forecast Demand Supply Balance

Based on the assumed demand forecast and system development scenario, the installed capacity reserve margin in the generation system will fluctuate between an estimated 28 and 33 percent during the period 1993-2000.

In a system of this size, such reserve margins are more than adequate to maintain acceptable reliability. Indeed, the probability of loss of load will average approximately 0.5 percent or much less if international exchanges and other non-firm resources are included.

Another useful measure of system adequacy is the effective thermal capacity reserve margin, which is obtained as the difference between total effective thermal capacity and the peak load to be carried by the thermal system. Effective capacity of a thermal generating unit is the maximum continuous rating (MCR) reduced by the fraction of time that such MCR is expected to be unavailable for maintenance or repair.

In Poland, effective thermal reserve margins are forecast to fluctuate between 8 and 14 percent. Effective reserve margins of less than 5 percent have been found to be adequate on very large systems (over 50,000 MW). Thus, the levels forecast for Poland appear adequate.

## 3.4 CAPITAL INVESTMENT ASSUMPTIONS

### 3.4.1 Investments in Modernization

PPGC assumes an extensive plan of rehabilitation in existing power units for the purposes of life extension, efficiency and reliability improvements, and also environmental compliance. According to these plans, between 1992 and 2000 there will be a total of 2,865 MW of capacity undergoing some form of rehabilitation. This includes the conversion to lignite of two units of the Patnow plant, which is currently burning residual oil (mazout), and an extensive plan of modernization of many of the existing 200 MW units. PPGC estimates that all these modernizations will include the addition of flue gas desulfurization devices (FGD) plus improvements in efficiency and reliability. The cost has been estimated by PPGC at US $800/kW or $2,292 million.

Because of the wide spectrum of possibilities and objectives in the rehabilitation of generating units, PPGC has indicated that, during the update of the expansion plan that is now underway, special emphasis will be placed on the analysis and ranking of economically feasible rehabilitation alternatives.

The bulk of the investment in modernizations will take place after 1994 and will thus not directly affect the 1994 tariff levels. It is nonetheless necessary to include an estimate of capital investments in modernizations during the 1993-1997 period. This will allow the establishment of a forecast of financial revenue requirements (Chapter 5) capable of recovering medium-term investments consistent with the emission standards by 1997 and with the most likely modernizations not directly related to compliance with emission standards.

### Modernizations for Compliance with Emission Targets

As part of this study, the emission standards set by the Polish Government and the current level of compliance by different plants were reviewed in an effort to estimate the extent of investments in environmental controls required for full compliance. Some of the existing estimates of the benefit/cost ratios of different opportunities for improvements in efficiency, power output, and reliability were also reviewed.

Appendix 3.1 includes a description of the various technologies available, their costs, and the details of the estimated needs of the Polish system. The main conclusions are that about 15,500 MW of current capacity would need sulfur dioxide (SO2) emissions controls, at an estimated cost of US $200/kW and most of existing capacity will need NOx emission controls at an estimated cost of $100/kW. Further, about 465,000 tons/year of dust need controlling, at an estimated cost of $45 to $70/kW. The total estimated cost for bringing the system into full compliance with 1997 emission standards is $6.1 billion.

### Modernizations Not Directly Aimed at Environmental Compliance

A review was made of studies conducted recently to assess the needs, costs and benefits of modernization of the largest coal-fired plants. Alternative efforts in modernization include the following major components: steam turbine, generator and excitation system, boiler and auxiliaries. For each of these components, several options were examined and ranked according to an objective function that includes consideration of reduced heat rate, increased availability rate, increased net output, and reduced operating and maintenance cost.

From the review of these studies, it was determined that out of approximately 30 individual types of improvements, four are sufficiently attractive to undertake in most large (120 MW and above) generating units. These are:

- Replace high-pressure turbine blading with modern design and improved seals.
- Replace entire low-pressure turbine.
- Improve insulation in the generator rotors and replace DC exciters with brushless or static exciters.
- Replace boiler ducts in start-up systems.

The cost varies with different types of units, but it is estimated that a package including these improvements could cost approximately $9.6 million for a 200 MW unit or about $48/kW. While more expensive modernizations are possible, it appears unlikely that under the current situation of adequate capacity reserve margin, such modernizations will be found justifiable in the medium term.

The estimated investments in both environmental and non-environmental modernization were incorporated into the financial analysis of individual plants (Chapter 5) by comparing estimated needs with specific rehabilitation investment plans.

### 3.4.2 New Generation Capacity

Only capacity additions planned up to the year 2000 can be assumed to affect revenue requirements between 1994 and 1997. These are: the Opole project (2,160 MW), the Mloty hydroelectric project (750 MW), three 150 MW gas turbines, and 2,340 MW of electric capacity in CHP plants.

The Opole project is under construction. It has an estimated cost of $1,200/kW or $2,592 million.

The 750 MW Mloty pumped storage project is estimated to require investments of $684/kW, of which $51/kW has already been spent and $633/kW remains to be disbursed, or $475 million.

PPGC estimated the capital cost of gas turbines at $340/kW. This value is consistent with international prices for large gas turbines and was used in this study in connection with units of 150 MW size. Thus, 450 MW of capacity will cost $143 million.

The capital cost of capacity installed in new CHP plants has not been estimated for this study. The pricing of CHP power will be discussed later in this report.

Although not affecting revenue requirements in the medium term, it is relevant to consider the capital cost of baseload generation (the purpose of this will become clear later in the analysis). The next baseload plant in PPGC scenario Ic consists of 370 MW of lignite-fired units; PPGC estimates its cost at $1,330/kW. This value is also considered reasonable for large plants with adequate environmental control facilities.

## 3.5 OPERATING COSTS ASSUMPTIONS

### 3.5.1 Operation and Maintenance Costs

The operation and maintenance (O&M) costs of powerplants must include salaries, maintenance contracts, lubricants and replacement of parts, and auxiliary equipment of the generating units. O&M costs do not include fuel and or any annual fixed charges on plant capital costs such as interest on debt, return on equity, depreciation, amortization and taxes. While there are no strict definitions to differentiate between regular maintenance and major rehabilitations, in general terms, any expense that is not related to fuel supply or to the book value of the assets is considered an O&M cost.

Actual cost is currently used to recover O&M expenses in the settlement of accounts between PPGC and generating plants. However, it is policy to move towards some form of cost standardization. It is a major effort to develop detailed guidelines for such a standardization, particularly given the uncertainties about real increases in wages and the additional operating expenses involved in emission reduction. For the purposes of this study, a comparison was made of O&M costs among Polish plants and in relation to comparable plants in other countries. The objective of this exercise was to develop a simple and reasonable assumption of O&M costs in Polish plants at economic level.

Such a comparison is only approximate because accounting practices vary across countries and some important cost items may or may not be included in all cases. Also, there is no uniform unit of measure; in some cases O&M costs are reported as variable costs (i.e., per unit of energy produced), in others they are reported as fixed costs (i.e., per unit of installed

capacity), and more commonly they are reported in both fixed and variable components. For simplicity all O&M costs in this study are defined as fixed costs expressed in equivalent US$ spent annually per installed kW of capacity.

The following is the range of O&M costs in Poland and other countries:

| | |
|---|---|
| Poland: | 11 to 45 US$/kW-Year |
| Western Europe: | 10 to 58 US$/kW-Year |
| US and Canada: | 11 to 40 US$/kW-Year |
| Australia: | 13.6 US$/kW-Year |
| Japan: | 77.5 US$/kW-Year |

It appears that current O&M costs in Poland are not unreasonable, except that it will be necessary to keep these costs at current levels in real terms, despite the expected increases in both real wages and emissions reduction. It will be a managerial challenge to maintain costs at current real levels, and the bulk power pricing mechanism must provide the necessary signals.

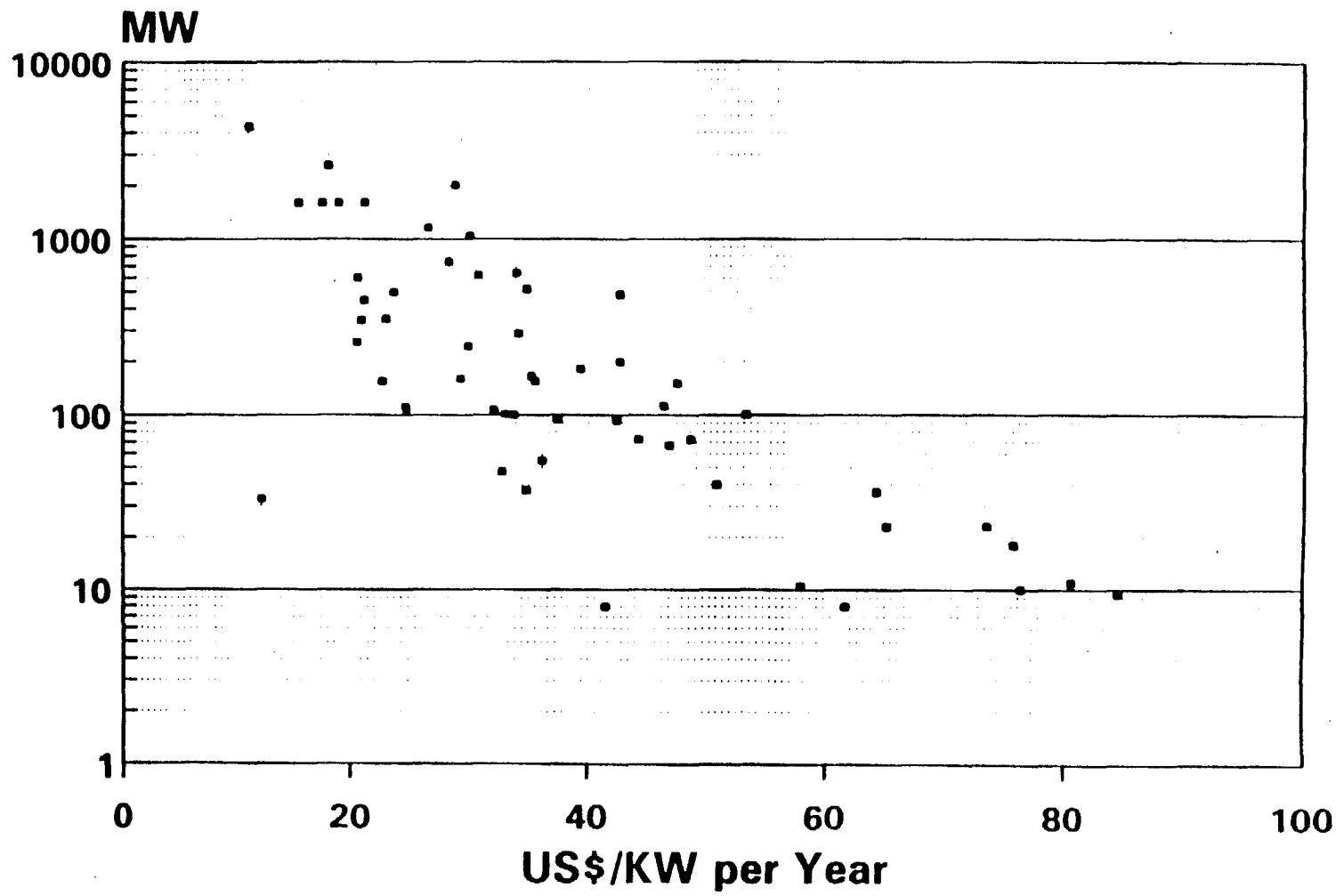
Within Polish plants there is a fairly strong inverse correlation between unit O&M cost and installed capacity, as shown in Exhibit 3-2. For the purposes of allocating economic O&M costs, plants were classified into one of three groups: below 500 MW, between 500 and 1,000 MW, and above 1,000 MW of installed capacity. O&M costs of $30/kW-Year, $25/kW-Year and $15/kW-Year were assigned to each group, respectively. This is probably too simplistic a system for standard O&M costs, but any formula that is adopted should, on average, yield comparable results.

### 3.5.2 Fuel Costs

The underlying assumption leading to the adoption of PPGC's scenario Ic (low demand growth and low availability of natural gas) is that while natural gas may eventually prove to be economically available in sufficient quantities for baseload generation, this availability remains too uncertain to be considered in a medium-term analysis. Thus, traditional fuels (lignite and coal) are the only fuels considered for baseload operation. Natural gas is assumed to be available for peaking operation since this mode demands modest quantities of fuel and the only alternative fuel for peaking units, diesel oil, is exceedingly expensive.

# Exhibit 3.2

## Operation and Maintenance Costs




RCG/Hagler, Bailly, Inc.

### Economic Price of Coal

There is a wide variation in coal prices both in Poland and in the international market. For the purposes of an economic analysis, internal market prices are not relevant. Instead, the economic cost to the Polish economy must be computed on the basis of the world market price of coal delivered to the Polish border (known as the "border" price) plus the cost of inland transportation to the point of use.

We have derived the economic price of coal from two sources: the World Bank's current forecast of the international coal price and PPGC's own estimate of the cost of coal with all subsidies removed.

The World Bank forecast appears as Exhibit 3-3. The US Dollar coal price (FOB, U.S. port of loading) is adjusted for international transport to Poland (CIF port of unloading). The expected 1992 average price is $50.0 per metric tonne. Based on the heat content of the coal used in the Bank estimate, the resulting economic cost is $1.79 $/GJ[1].

PPGC has calculated the non-subsidized cost of coal used at each generating station in 1991. Exhibit 3-4 reports these values for the five largest coal plants. The weighted average cost of coal, excluding transport cost, is 1.24 $/GJ. Increasing this value by domestic inflation to 1992, the resulting economic cost of coal is 1.72 $/GJ. The World Bank annual forecast assumes variable annual real price adjustments (both positive and negative). Due to model constraints, no real price escalation has been assumed in this study.

Based on these two sources, we have assumed an average border cost of 1.79 $/GJ. This cost was further adjusted by the average value of internal transport. Exhibit 3-5 shows that transport adds a weighted average of 12.7 percent to the minemouth coal cost of the 10 largest coal stations.[2] The resulting average delivered economic cost of coal applied for this study is 2.01 $/GJ.

Exhibit 3-6 reports the financial costs of coal and lignite (i.e., contract prices with subsidies) delivered to the five largest generating stations of each type. Escalated to 1992 prices, the average cost of delivered coal is 1.53 $/GJ.

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[1] GJ = $10^9$ Joules

[2] As noted above, PPGC has calculated all of these costs exclusive of subsidies, duties, and taxes.

Exhibit 3.3
World Bank Coal Forecast

IBRD Fuel Price Assumptions – Based on 10/92 IBRD Crude Forecast

| Calendar Year | COAL/FOB Current $/MT | COAL/FOB CY 85 $/MT | MUV Index Imputed | COAL/FOB CY 92 $/MT | COAL/CIF CY 92 $/MT | COAL CY 92 tysZl/MT | COAL CY 92 $/GJ |
|---|---|---|---|---|---|---|---|
| 1992 | 41.00 | 27.00 | 151.85 | 41.00 | 50.00 | 670.00 | 1.80 |
| 1993 | 42.00 | 26.00 | 161.54 | 39.48 | 48.48 | 649.65 | 1.74 |
| 1994 | 44.00 | 27.00 | 162.96 | 41.00 | 50.00 | 670.00 | 1.80 |
| 1995 | 46.00 | 27.00 | 170.37 | 41.00 | 50.00 | 670.00 | 1.80 |
| 1996 | 48.83 | 27.57 | 177.08 | 41.87 | 50.87 | 681.70 | 1.83 |
| 1997 | 51.83 | 28.16 | 184.05 | 42.76 | 51.76 | 693.65 | 1.86 |
| 1998 | 55.02 | 28.76 | 191.30 | 43.68 | 52.68 | 705.85 | 1.89 |
| 1999 | 58.41 | 29.37 | 198.84 | 44.61 | 53.61 | 718.32 | 1.92 |
| 2000 | 62.00 | 30.00 | 206.67 | 45.56 | 54.56 | 731.04 | 1.96 |
| 2001 | 64.23 | 30.00 | 214.11 | 45.56 | 54.56 | 731.04 | 1.96 |
| Avg Rate | 5.1% | 1.2% | 3.9% | 1.2% | 1.0% | 1.0% | 1.0% |
| Period | 1992–01 | 1992–01 | 1992–01 | 1992–01 | 1992–01 | 1992–01 | 1992–01 |

NOTES:

13.4 tysZl/$

27.9 GJ/MT Coal

$9.00 estimated Coal transport cost per tonne from USA port of loading to port of European unloading.

Exhibit 3.4
Non – Subsidized Cost of Coal and Lignite by Plant
PPGC Estimates for 1991

| | Quantity Consumed MT | Calorific Value kJ/kg | Fuel Cost tysZl/MT | Transport Cost tysZl/MT | Total Cost tysZl/MT | Fuel Cost tysZl/GJ | Total Cost tysZl/GJ | Total Cost $/GJ |
|---|---|---|---|---|---|---|---|---|
| **Largest Lignite Stations** | | | | | | | | |
| EL Belchatow | 27213 | 7633 | 118.731 | 0.000 | 118.731 | 15.555 | 15.555 | 1.161 |
| EL Turow | 12035 | 8949 | 117.882 | 0.000 | 117.882 | 13.173 | 13.173 | 0.983 |
| EL Patnow | 7628 | 9244 | 135.131 | 0.000 | 135.131 | 14.618 | 14.618 | 1.091 |
| EL Konin | 3148 | 9059 | 135.131 | 0.000 | 135.131 | 14.917 | 14.917 | 1.113 |
| EL Adamow | 2875 | 7955 | 149.431 | 0.000 | 149.431 | 18.785 | 18.785 | 1.402 |
| Weighted Average | – | 8267 | 123.547 | 0.000 | 123.547 | 15.015 | 15.015 | 1.121 |
| Estimated 1992 Price 1/ | | | | | | 20.721 | 20.721 | 1.546 |
| **Largest Coal Stations** | | | | | | | | |
| EC Rybnik | 9252 | 21626 | 404.349 | 25.631 | 429.980 | 18.697 | 19.883 | 1.484 |
| EC Kozienice | 7996 | 21055 | 393.656 | 61.427 | 455.083 | 18.697 | 21.614 | 1.613 |
| EC Polaniea | 7173 | 18980 | 294.974 | 48.051 | 343.025 | 15.541 | 18.073 | 1.349 |
| EC Dolna Odra | 6856 | 21988 | 390.814 | 80.726 | 471.540 | 17.774 | 21.445 | 1.600 |
| EC Jaworzno III | 6302 | 17777 | 278.950 | 26.000 | 304.950 | 15.692 | 17.154 | 1.280 |
| Weighted Average | – | 20420 | 357.698 | 47.641 | 405.338 | 17.422 | 19.733 | 1.473 |
| Estimated 1992 Price 1/ | | | | | | 24.043 | 27.232 | 2.032 |
| LIGNITE : COAL (%) | | 40% | – | – | – | 86% | 76% | 76% |

1/ 1991 prices escalated by 38% (reported annual inflation from 1991 to 1992)
2/ Foreign exchange rate assumed 13.400 tysZl / $

Exhibit 3.5

Non-Subsidized Share of Transport to Total Cost of Coal for Largest Plants

PPGC Estimates for 1991

| Coal Station | Quantity Consumed MT | Fuel Cost tysZl/MT | Transport Cost tysZl/MT | Total Cost tysZl/MT | Transport Percent of Fuel Cost |
|---|---|---|---|---|---|
| EC Rybnik | 9.252 | 404.349 | 25.531 | 429.880 | 6.3% |
| EC Kozienice | 7.996 | 393.656 | 61.427 | 455.083 | 15.6% |
| EC Polaniea | 7.173 | 294.974 | 48.051 | 343.025 | 16.3% |
| EC Dolna Odra | 6.856 | 390.814 | 80.726 | 471.540 | 20.7% |
| EC Jaworzno III | 6.302 | 278.950 | 28.000 | 306.950 | 10.0% |
| EC Ostroleka | 2.864 | 282.901 | 67.300 | 350.201 | 23.8% |
| EC Laziska | 4.286 | 413.504 | 13.272 | 426.776 | 3.2% |
| EC Lagisza | 3.423 | 306.996 | 27.899 | 334.895 | 9.1% |
| EC Siersza | 3.128 | 319.775 | 24.702 | 344.477 | 7.7% |
| EC Stalowa Wola | 1.356 | 318.780 | 62.445 | 381.225 | 19.6% |
| **Weighted Average** | – | **351.619** | **43.868** | **395.487** | **12.7%** |

Exhibit 3.6
Subsidized Cost of Coal and Lignite by Plant
PPGC Estimates for 1991

| | Quantity Consumed MT | Calorific Value kJ/kg | Fuel Cost tysZl/MT | Transport Cost tysZl/MT | Total Cost tysZl/MT | Fuel Cost tysZl/GJ | Total Cost tysZl/GJ | Total Cost $/GJ |
|---|---|---|---|---|---|---|---|---|
| **Largest Lignite Stations** | | | | | | | | |
| EL Belchatow | 27213 | 7633 | 84.808 | 0.000 | 84.808 | 11.111 | 11.111 | 0.829 |
| EL Turow | 12035 | 8949 | 84.059 | 0.000 | 84.059 | 9.393 | 9.393 | 0.701 |
| EL Patnow | 7628 | 9244 | 96.522 | 0.000 | 96.522 | 10.442 | 10.442 | 0.779 |
| EL Konin | 3148 | 9059 | 96.522 | 0.000 | 96.522 | 10.655 | 10.655 | 0.795 |
| EL Adamow | 2875 | 7955 | 106.736 | 0.000 | 106.736 | 13.417 | 13.417 | 1.001 |
| Weighted Average | – | 8267 | 88.216 | 0.000 | 88.216 | 10.722 | 10.722 | 0.800 |
| Estimated 1992 Price 1/ | | | | | | 14.796 | 14.796 | 1.104 |
| **Largest Coal Stations** | | | | | | | | |
| EC Rybnik | 9252 | 21626 | 288.749 | 26.531 | 315.280 | 13.352 | 14.579 | 1.088 |
| EC Kozienice | 7996 | 21055 | 281.190 | 61.427 | 342.617 | 13.355 | 16.272 | 1.214 |
| EC Polanica | 7173 | 18980 | 210.696 | 48.051 | 258.747 | 11.101 | 13.633 | 1.017 |
| EC Dolna Odra | 6856 | 21988 | 279.153 | 80.726 | 359.879 | 12.696 | 16.367 | 1.221 |
| EC Jaworzno III | 6302 | 17777 | 199.964 | 26.000 | 225.964 | 11.248 | 12.711 | 0.949 |
| Weighted Average | – | 20420 | 255.602 | 47.862 | 303.464 | 12.450 | 14.772 | 1.102 |
| Estimated 1992 Price 1/ | | | | | | 17.182 | 20.385 | 1.521 |
| LIGNITE : COAL (%) | | 40% | – | – | – | 86% | 73% | 73% |

1/ 1991 prices escalated by 38% (reported annual inflation from 1991 to 1992)
2/ Foreign exchange rate assumed 13.400 tysZl / $

### Economic Price of Lignite

Due to its low heating value per tonne and high sulfur content, lignite does not have a well defined international trading value. As noted above, PPGC has calculated the cost of fuel exclusive of subsidies for all lignite-fired stations. Exhibit 3-4 shows the weighted average share of delivered lignite to coal cost for the five largest plants of each type. The unsubsidized lignite is estimated to cost 76 percent of the delivered cost of coal. This lower price is deemed to be fairly consistent with the additional cost of burning lignite at emission levels comparable to those of coal. This factor was applied to estimate the economic cost of lignite at 1.53 $/GJ.

The subsidized cost of lignite is estimated in Exhibit 3-6 to be 1.11 $/GJ.

### Economic Price of Gas

As noted above, there are currently no gas-fired units in Poland, and domestic gas availability is limited. Although many options are being studied, no long-term international supply agreements are in place. Further, no formal gas utilization study has been prepared. Given the limited availability of gas, it is reasonable to assume that it will only be available for higher-value applications.

The price of gas was estimated from our projections of oil product prices, which are derived from the World Bank's current crude forecast. Exhibit 3-7 reports the crude price projection and estimated product price forecasts. We have assumed that mazout is priced at 80 percent of crude and distillate at 140 percent of crude on a heat equivalent basis.

The price of Gas in Germany *exclusive of tax* averaged 87 percent of distillate and 159 percent of mazout on a heat equivalent basis from 1986 through 1990. Applying these percentages to our projected oil product prices, a gas price of 3.27 $/GJ based on mazout and 3.36 $/GJ based on distillate is obtained. Thus, an average gas price of 3.32 $/GJ has been used for this study.

## 3.5.3 Cost for the Use of the Environment

The Polish Government levies a charge for the release of emissions and the disposal of ash from power plants. At present, this is not a proxy for the actual economic cost of reducing such emissions. Rather, it is a form of tax or internal transfer within the economy.

**Exhibit 3.7**
**CONSTANT PRICE FUEL FORECAST (1992 PRICES)**

| Year | CRUDE 1992 $/bbl | MAZOUT % CRUDE | MAZOUT $/bbl | MAZOUT $/tonne | MAZOUT tysZl/tonne | MAZOUT $/mmbtu | |
|---|---|---|---|---|---|---|---|
| 1992 | 17.400000000 | 80% | 13.92000000 | 87.6960000 | 1,175.12640 | 2.18 | |
| 1993 | 17.094736842 | 80% | 13.67578947 | 86.1574737 | 1,154.51015 | 2.14 | |
| 1994 | 17.247368421 | 80% | 13.79789474 | 86.9267368 | 1,164.81827 | 2.16 | |
| 1995 | 17.857894737 | 80% | 14.28631579 | 90.0037895 | 1,206.05078 | 2.23 | ) |
| 1996 | 18.403518751 | 80% | 14.72281500 | 92.7537345 | 1,242.90004 | 2.30 | 2.30 ) 3-yr avg |
| 1997 | 18.965813575 | 80% | 15.17265086 | 95.5877004 | 1,280.87519 | 2.37 | ) |
| 1998 | 19.545288563 | 80% | 15.63623085 | 98.5082544 | 1,320.01081 | 2.44 | |
| 1999 | 20.142468632 | 80% | 16.11397491 | 101.5180419 | 1,360.34176 | 2.52 | |
| 2000 | 20.757894737 | 80% | 16.60631579 | 104.6197895 | 1,401.90518 | 2.59 | |
| 2001 | 20.788331663 | 80% | 16.63066533 | 104.7731916 | 1,403.96077 | 2.60 | |

| Year | CRUDE 1992 $/bbl | DISTILLATE % CRUDE | DISTILLATE $/bbl | DISTILLATE $/tonne | DISTILLATE tysZl/tonne | DISTILLATE $/mmbtu | |
|---|---|---|---|---|---|---|---|
| 1992 | 17.400000000 | 140% | 24.36000000 | 172.9560000 | 2,317.61040 | 4.06 | |
| 1993 | 17.094736842 | 140% | 23.93263158 | 169.9216842 | 2,276.95067 | 3.99 | |
| 1994 | 17.247368421 | 140% | 24.14631579 | 171.4388421 | 2,297.28048 | 4.02 | ) |
| 1995 | 17.857894737 | 140% | 25.00105263 | 177.5074737 | 2,378.60015 | 4.17 | 4.16 ) 3-yr avg |
| 1996 | 18.403518751 | 140% | 25.76492625 | 182.9309764 | 2,451.27508 | 4.29 | ) |
| 1997 | 18.965813575 | 140% | 26.55213901 | 188.5201869 | 2,526.17050 | 4.43 | |
| 1998 | 19.545288563 | 140% | 27.36340399 | 194.2801683 | 2,603.35428 | 4.56 | |
| 1999 | 20.142468632 | 140% | 28.19945609 | 200.2161382 | 2,682.89625 | 4.70 | |
| 2000 | 20.757894737 | 140% | 29.06105263 | 206.3334737 | 2,764.86855 | 4.84 | |
| 2001 | 20.788331663 | 140% | 29.10366433 | 206.6360167 | 2,768.92262 | 4.85 | |

*NOTES:*

*13.4 tysZl/$*

*6.4 mmbtu/bbl Mazout*

*6.3 bbl/tonne Mazout*

*42.6 mmbtu/tonne Distillate*

*7.1 bbl/tonne Distillate*

*0.8 Mazout:Crude price relationship*

*1.4 Distillate:Crude price relationship*

As an internal transfer, this cost item needs to be included in the financial analysis of revenue requirements of the generating system but does not represent an economic cost any more than the income taxes or import duties paid by the power plants. The implication of these taxes for a system of transfer prices based on economic marginal costs will be addressed as part of the next section.

## 3.6 GENERATION SYSTEM STRUCTURE IN 1994

According to current policy, in 1994 the public generation system will be structured as follows:

- four generating utilities that own and operate the majority of conventional and collector grid plants burning coal
- Three regional lignite authorities that will own and operate all lignite mines and associated conventional grid plants
- CHP plants and some collector grid plants will be independently owned or under the authority of district heating or distribution utilities
- run-of-river hydroelectric plants owned and operated by distribution companies
- pumped storage hydroelectric plants owned and operated by PPGC.

Regardless of their ownership, all plants delivering power to the high-voltage grid (110 kV and above) will be under central dispatch control and subject to PPGC's pricing system. However, any utility or power plant may be allowed to contract directly with a distribution company when such power transfers occur outside the high-voltage grid.

## 3.7 PRICING PRINCIPLES FOR GENERATION IN 1994

### 3.7.1 Current System and Issues

The current principle of settlements for power purchases from generators is based in cost recovery. PPGC pays generating plants the actual costs deemed to have been involved in generating power, with some averaging of all plants involved in the computations of asset depreciation. The system involves elaborate accounting of all costs in each plant, and PPGC

is moving towards a system in which a majority of costs are standardized, thereby simplifying power transactions and providing signals for greater efficiency in generation.

One major issue at present is the recovery of fixed costs for capacity that is not essential to the system under the current situation of excessive capacity reserve. This non-essential capacity is the fraction of available capacity in excess of capacity ordered by central dispatch to meet short-term expected demands.

PPGC currently negotiates with each plant the fraction of fixed costs that is allowed to be recovered on non-essential capacity. However, it is unclear whether a similar type of negotiation will take place for the aggregated non-essential capacity of each generating utility.

### 3.7.2 Recommended Principles

The ideal pricing system for a fully decentralized power sector would be one based entirely on the value of power to the system at any given time. One form of value-based compensation is bidding. In such a system generators quote prices for power and the grid buys what it needs from the cheapest source. An alternative form of value-based compensation is avoided cost pricing. Here, the grid calculates the least cost of producing power and offers to pay that price to the generators.

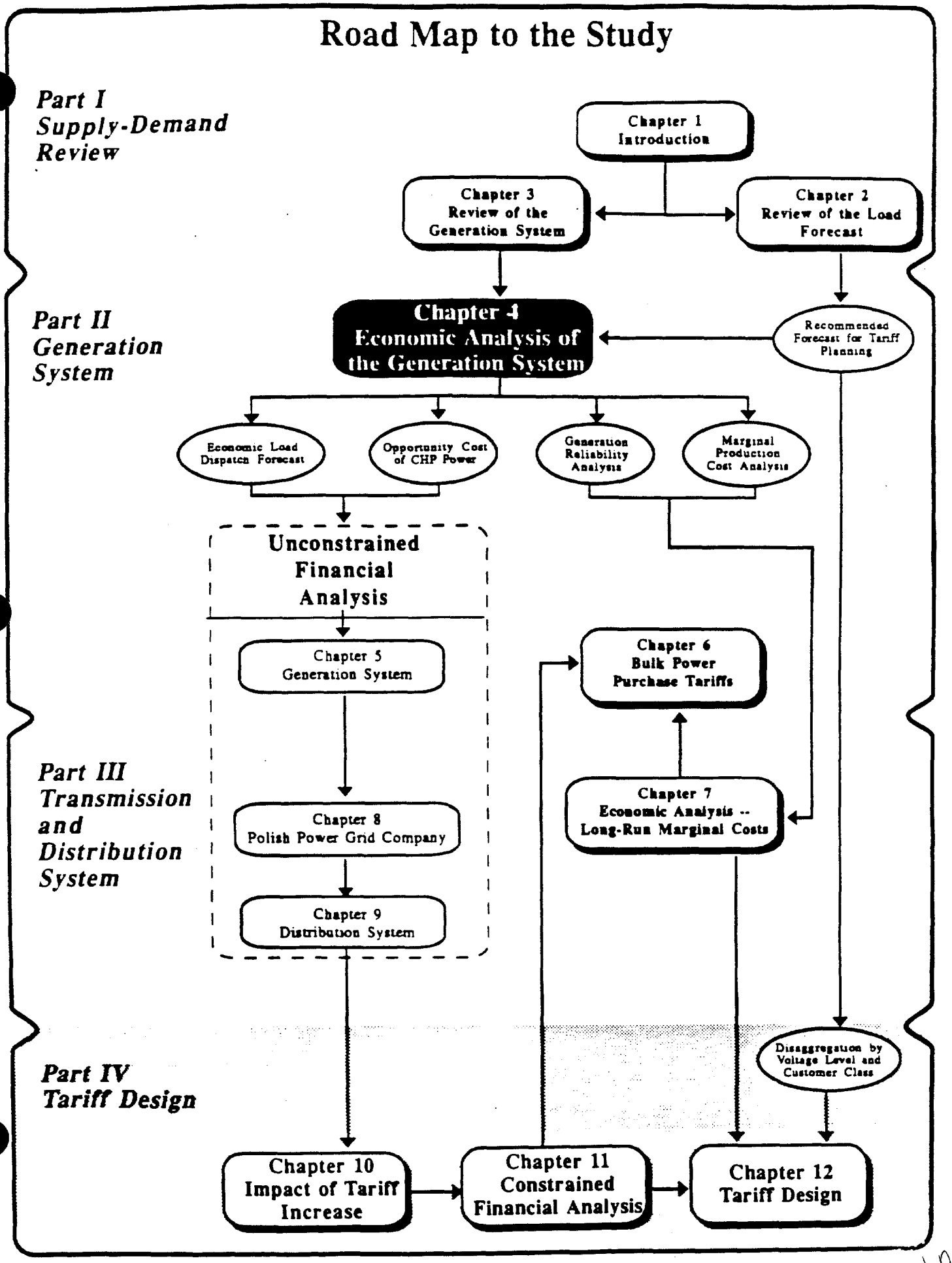
A pure value-based system is possible in Poland and may be desirable at some future time. However, it does not appear to be a practical system for 1994. The Polish generation system evolved under a centrally planned economy in which each individual component was not expected to reflect the optimum economic alternative, but rather, to fit in a plan deemed to maximize benefits across many sectors. It is therefore recommended that a prudent period of time be allowed for utilities and individual power plants to adjust their costs to competitive levels.

Within this constraint, it is possible to move ahead in the standardization of many cost components and to shift entirely to value based-pricing for some specific types of resources. In particular, a value-based system seems very adequate to be applied as early as 1994 to those resources that are not primarily dedicated to the power sector, such as CHP plants and power surplus from autoproducers.

Thus, it is recommended that the majority of power generation (i.e., from conventional grid plants) be purchased on a cost-based pricing basis with increasing reliance on standard costs. The remainder of generation should be based on avoided costs to the system.

These recommended principles will be elaborated on in Chapter 6, which deals with bulk power purchase tariffs.

# Road Map to the Study

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computation of avoided costs usee the same simulation procedure, but under different scenarios of system expansion with and without the CHP component.

The final step was to calculate the marginal production costs of the generation system for every hour of each week representative of the seasons determined above for possible differentiated pricing. These costs were also used to define the marginal cost corresponding to different pricing periods during that week.

## 4.2 GENERATION RELIABILITY ANALYSIS

The marginal cost of power generation fluctuates with the hourly demand for two reasons:

- the generating units typically are dispatched in order of increasing energy cost
- the higher the load, the more likely it is that it cannot be met by *all* available generating units, resulting in loss of load.

This last effect drives the demand charge or capacity component of a power tariff formula and is generally more sensitive to the demand level than the energy component. Therefore, tariff periods are based on a generation reliability analysis reflecting the capacity component only.

A detailed description of the analysis, the theoretical background, and the software involved is provided in Appendix 4.1. Only the results and the major factors influencing these results are presented in this section.

### 4.2.1 Loss of Load Probability

The generation reliability analysis determines the probability that the demand for power will be in excess of available capacity for each hour of a forecast year. This probability is called "loss-of-load probability," or LOLP.

The average LOLP over a period is called the "period LOLP," and it can be interpreted as the probability of loss of load at a random time in the period. The variation of LOLP over a forecast year is due primarily to the variation of the hourly loads, although it also results from changes in the generation system (typically assumed to occur at most monthly), such as seasonal changes in supply and removals of units for annual maintenance.

Exhibit 4-1 shows the major steps of the analysis for the determination of LOLP.

# CHAPTER 4: ECONOMIC ANALYSIS OF THE GENERATION SYSTEM

## 4.1 OBJECTIVES AND APPROACH

The economic analysis of the generation system was used to develop the following products to be used in making recommendations for bulk power tariffs:

- *The forecast of power production by plant based on economic load dispatch principles.* This forecast was used to determine financial revenue requirements for each plant and generating company, and the generating system as a whole (Chapter 5).

- *The pattern of reliability of the generating system during the year and during different times of the week and the day.* This pattern was used to establish tariff periods to signal to customers the differential economic cost of operating at different times (Chapter 7).

- *The pattern of marginal costs of the generating system during the year and during different times of the week and the day.* This pattern was used to establish the marginal cost pricing level of each tariff period and subsequently, to shape the collection of financial revenue requirements according to a marginal cost structure.

- *The avoided cost of central heat and power (CHP) power to the power system computed through differential economic revenue requirements.* This value was used as a reference in the negotiation of avoided cost tariffs with all sources of power not entirely dedicated to the power sector (Chapter 6).

The approach taken to the economic analysis of the generation system has several steps. First, a detailed reliability analysis was conducted for the generation system, using 1997 as a year representative of the time when economic signals given in 1994 can produce an impact in terms of generation system investments and costs. This analysis provided the basis for selecting pricing periods on which marginal costs need to be determined.

The step was a detailed simulation of the operation of the generation system. Because this simulation meets several needs of both the financial and economic analyses, it needed to be both long term to allow for a determination of long-term avoided costs and plant production forecasts, and have sufficient resolution over each year to determine the operational characteristics of the generating system during each season for which marginal costs are to be differentiated. The

### 4.2.2 Major Factors Affecting the Determination of LOLP

In addition to load variation, the two most important factors in determining LOLP in the Polish system are the dispatch of pumped storage hydro and the scheduling of planned maintenance of thermal resources. The dispatch of pumped storage affects the distribution of reliability during the day, while the scheduling of planned maintenance of thermal units affects the distribution of reliability over the year. The major conclusions are as follows:

- The current use of pumped storage is consistent with the objectives of keeping system reliability as uniform as possible, but it may be necessary to examine the operation in more detail as predominantly peaking resources, gas turbines and the Mloty project enter the system in the medium term.

- It is possible to minimize variations in reliability throughout the year by the scheduling of planned maintenance in grid plants. Because the current maintenance schedule is probably affected by other constraints, reliability throughout the year is not as smooth as it could be.

### 4.2.3 Recommended Pricing Periods

For this study, reliability was analyzed over the forecast loads for the year 1997, with the forecast load shape based on the historical 1991 data summarized in Exhibit 4-2.

Within each day, LOLP is related directly to the loads, after they are adjusted for energy-limited generation such as pumped storage. The relation between LOLP and load shows increasing sensitivity as the load increases (this is shown in Exhibit 4-1). The result is the choice of tariff periods largely determined by daily load shapes and seasonal variations, such as the historical 1991 shapes of Exhibit 4-2.

Recent (1989-1991) historical load shapes show a morning peak period of about 8 a.m. to noon and an evening peak period that gradually starts later in the day and is shorter as the summer approaches. Weekend loads are significantly lower than weekday loads, as shown in Exhibit 4-3. The LOLP results confirmed these observations and led to the recommended tariff periods shown in Exhibit 4-4. This exhibit also shows recommended LOLP factors, which are rounded base-case results, to be used in the allocation of demand charges.

The recommended tariff periods divide the year somewhat arbitrarily into two seasons. These serve to reflect changes in the evening on-peak periods rather than changes in overall reliability,

**Exibit 4-1**
**LOLP Calculation Flowchart**

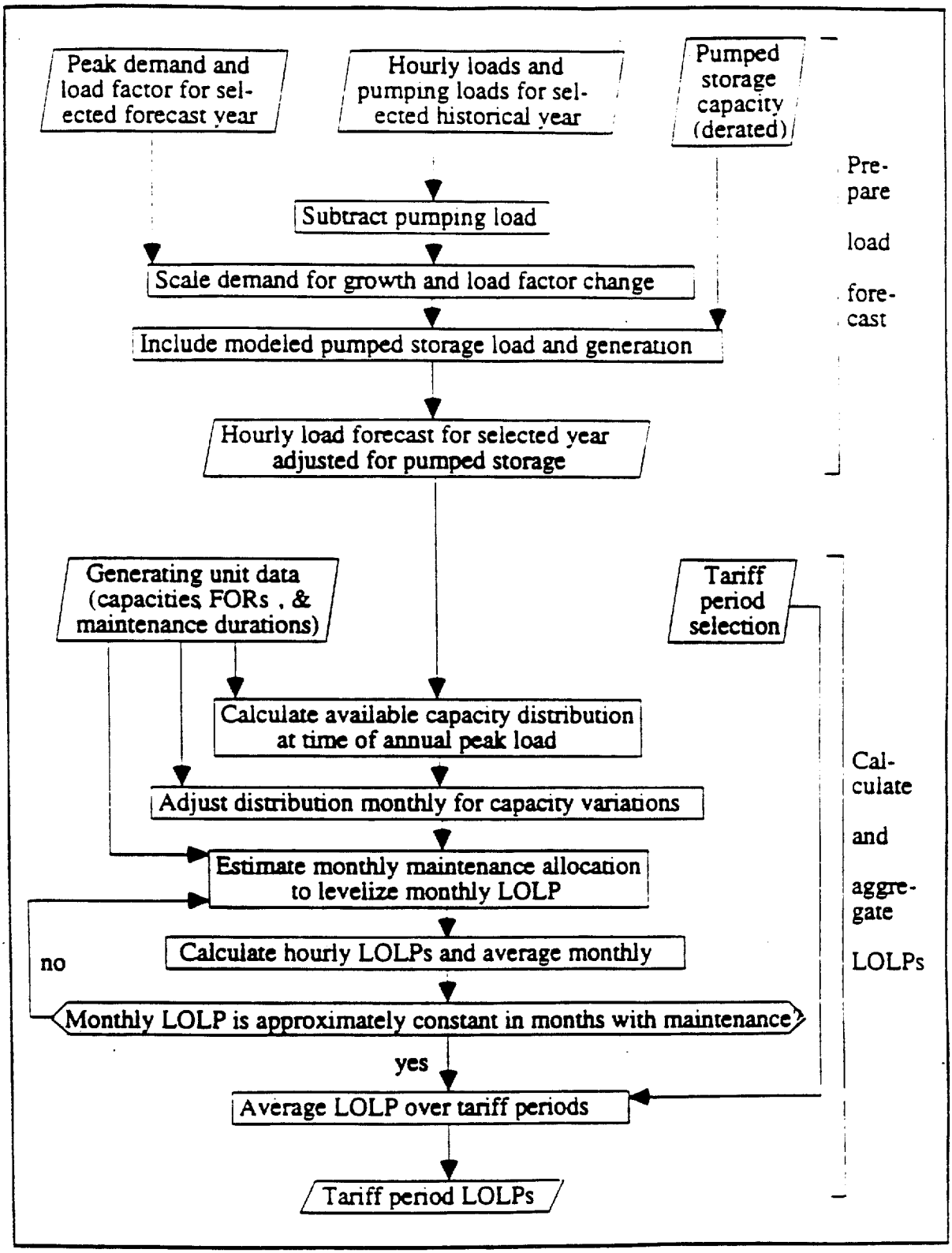
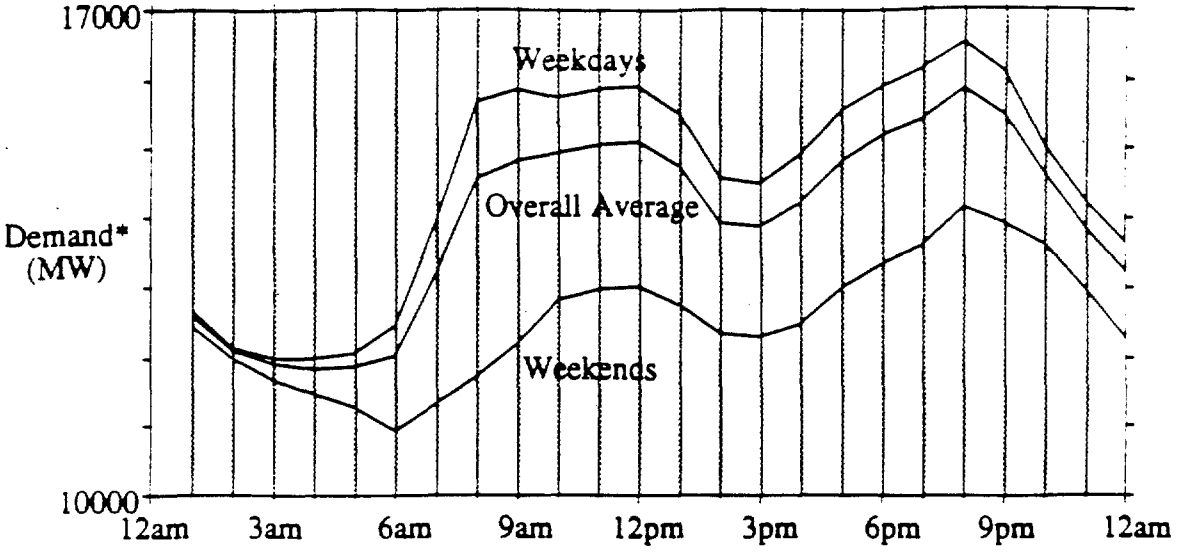


Exhibit 4.3
**Average Demand by TOD for Weekdays vs. Weekends in 1991**



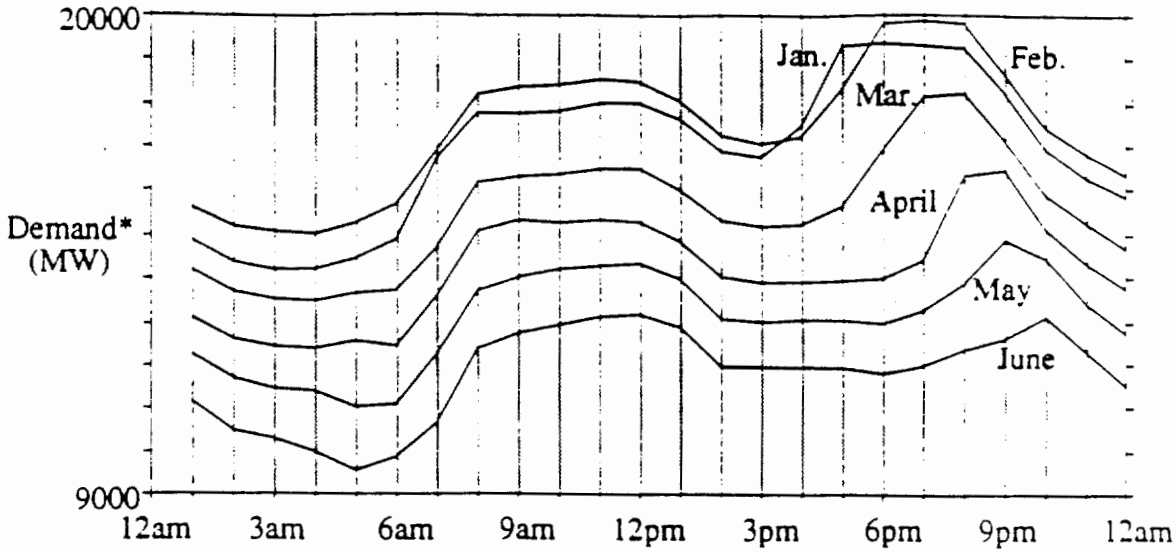

* Demand excludes pumping load and autoproducer self-load.

**Exhibit 4.4**
**Recommended Rating Periods and Their LOLPs**

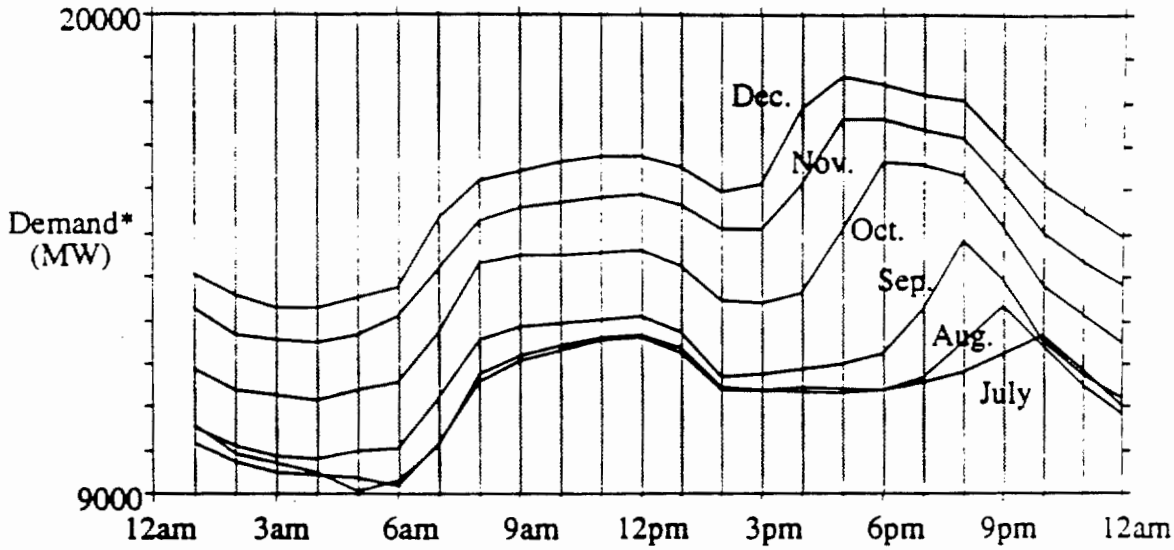
| Season | Morning Peak | Evening Peak | Combined Peak | Off-Peak |
|---|---|---|---|---|
| Winter = October-March | 7am-1pm weekdays: 186% | 4pm-9pm weekdays: 395% | Morning + evening periods: 281% | Remainder of week: 12.7% |
| Summer = April-September | 7am-1pm weekdays: 258% | 7pm-10pm weekdays: 318% | Morning + evening periods: 278% | Remainder of week: 34.2% |

Note: percentages are period LOLPs as a percentage of annual average LOLP, and their weighted average using period lengths as weights equals 100%, except for rounding error.

**Exhibit 4.2**
**Average Demand by TOD for each Month of 1991**




(a) January-June




(b) July-December

* Demand excludes pumping load and autoproducer self-load.

### Step 1 - Load Duration Curve Adjustment

The model uses two load duration curves, one for summer and one for winter, obtained from the analysis of historical loads in 1991. The load duration curves are expressed in non-dimensional form; that is, they do not show hours or MW, but merely the fraction of time that a certain fraction of the peak load is exceeded. As such, these load duration curves can be used for any peak load, but the load factor (i.e., the ratio between mean load and peak load for each season) will always be the same as it was in 1991. As discussed in Chapter 2, the forecast includes changes in load factor that need to be addressed when forecasting the production of the generating system. Thus, the first step is to adjust the load duration curves to meet the load factor forecast for each year and season of the simulation.

### Step 2 - Dispatch of Energy Limited Resources

Generating resources can be classified into two broad categories according to the mode in which they are dispatched to meet the load: *economically dispatchable* resources and *energy-limited* resources.

A conventional thermal plant can be considered to be a strictly economic resource in the sense that, given that its capacity is available, the only thing that limits the production of the plant is the load to be served and the cost of meeting the load with that plant in relation to other plants in the system. A hydroelectric plant, on the other hand, may produce very cheap energy and may have abundant capacity, but there is a limited amount of water available to produce energy. Thus, its production is at least partially determined by factors outside the dispatch. In between these classical examples there are many other resources that have characteristics common to both. For example, CHP plants in Poland are economically dispatched, but are constrained to produce only the amount of electric energy associated with the demand for heat.

The second step in GPT is to dispatch the energy-limited resources as if they had priority to serve load. The load served by these resources is simply subtracted from the load duration curve, creating a "residual" load duration curve to be supplied from the economically dispatchable resources.

### Step 3 - Economically Dispatchable Resources

Each unit in the conventional plants is dispatched from the base to the top of the residual load duration curve in order of increasing variable costs and following the rules of probabilistic

because the monthly LOLPs are approximately equal across the year (due to the maintenance allocation, modeled as described in the next section). Exhibit 4-4 also shows LOLP factors for the combined morning and evening peak periods, to provide an alternative, simpler tariff structure.

The periods in Exhibit 4-4 are similar to those used for the one-part and two-part tariff classes in a recent price list *(7-Z/92, Electricity SWW 0311, Warsaw 1992)*. However, the on-peak periods of Exhibit 4-4 exclude weekends and are somewhat broader. Also, minor monthly variations among evening on-peak periods within each season are ignored for simplicity.

### 4.2.4 Sensitivity Analyses

Nine sensitivity cases were studied, including the following:

- different load years
- addition and substraction of 500 MW of base load
- load forecast uncertainty included
- lower forced outage rates in generating units
- no pumping loads included
- historical vs. modelled pumped storage generation.

These analyses showed that the system is fairly insensitive to changes in assumptions, except for those concerning pumped storage operation and hourly load shapes.

Every few years, as the load shapes and generation system evolve (specially with the addition of the Mloty pumped storage plant), the choice of tariff periods and the allocation of costs to them should be reviewed. The computer software tailored for this analysis (see Appendix 4.1) can simplify such reviews.

## 4.3 SIMULATION OF THE OPERATION OF THE GENERATING SYSTEM

A detailed simulation of the generating system was carried out by PPGC in 1991 during the study of the system expansion plan. For the purposes of the tariff study, this simulation was updated using the model Generation Planning Tools (GPT).

The simulation was carried out for two seasons, summer and winter, of each year in the period 1993-2000. Each simulation (year-season) involves the following steps:

### CHP

CHP power is currently very much a dispatchable resource in spite of the limitations resulting from the association of CHP electric production and the demand for heat. However, there are two important factors weighing in favor of modelling this resource as energy limited:

- The economics of power and heat production from CHP plants are strongly interdependent, even though some CHP plants have power-dedicated boilers. The demand for heat is external to the power production process but acts as a constraint on how much power can be economically produced by the CHP plant.

- The representation of CHP dispatch constraints is much more accurate if treated as a limited energy resource.

### Economic Dispatch Criterion

The dispatch was performed using a set of rules that are closely linked to the assumptions made in connection with economic cost standards, as discussed in Chapter 3. These include:

- All plants using the same type of fuel have the same fuel cost, and this cost is deemed to be the opportunity cost or border price of the fuel.

- Operation and maintenance costs are normalized as a function of plant size.

- Environmental costs are not included in determining the ranking order of dispatch, because it is not clear that these represent true economic costs in the sense that a dispatch based the variable costs that would result may not provide a dispatch that leads to the best allocation of economic resources.

## 4.3.2 Results of the Simulation

A detailed report of the simulation is presented in Appendix 4.2 and contains the actual input and output files of the computer model GPT.

The input file (Section A.4.2.1 of Appendix 4.2) contains a large number of comments describing the use of each value in the file and comments specific to the sources of data and the modelling assumptions. Nevertheless, this is only included as a reference and it is not necessary for the understanding of the results.

convolution. The rules of probabilistic convolution determine that the production of any unit $i$ of capacity $P$ dispatched to meet load at a level $X$ is a function of the availability of that capacity $P$ and also of the shape of the load duration curve transformed by the probability that other units dispatched before unit $i$ will be available.

The result is a sequence or "stack" of generating units operating at decreasing capacity factors and increasing cost to produce the energy of the residual load duration curve. It is a feature of the probabilistic dispatch that there is always a finite amount of energy that remains not served. This is called the "expected unserved energy" and is a reliability parameter related to the "loss of load probability" (LOLP) discussed in Section 4.2.

### 4.3.1 Major Features of the Simulation

For the purposes of the tariff study, the system was modelled by including all hydroelectric plants, autoproducers, and CHP as energy-limited resources and all other plants as economically dispatchable resources. There are several reasons for treating each of those resources in this way; these are discussed below.

#### Hydroelectric Resources

The loads used in the simulation include the pumping loads forecast in the system. Thus, pumped storage hydro was treated as peak hydro with a limited amount of available energy. Conventional hydro has both peak and base load components and was superimposed on the pumped storage so that both were treated as a single composite hydroelectric resource.

#### Autoproducers

Autoproducer load was netted out of the load forecast. Thus, only the surplus power from autoproducers was included in the simulation. It is not clear what this output will be in the future but it is currently being purchased directly by the distribution companies, and is, in effect, "invisible" to the dispatch process. It was therefore adequate to represent it as an energy-limited resource with base and peak load components.

EXHIBIT 4.5

SAMPLE RESULTS OF THE DETAILED SIMULATION OF THE GENERATION SYSTEM FOR 1997

| STACK LEVEL MW | LOAD POINT MW | GENERATOR TYPE | & NAME | NET RATED MW | P.MAIN. DERATED MW | FORCED OUTAGE % | EFFECTIVE CAPACITY MW | ENERGY OUTPUT GWH | CAPAC. FACTOR % | CAPITAL ANNUITY M$ | FIXED O & M M$ | VARIABLE O & M M$ | FUEL COST M$ | TOTAL COST M$ | FIXED CHARGE $/KW | VARIABLE CHARGE cts/KWH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 160 | 2 | SL-PA-200 | 200.0 | 160.5 | 10.60 | 143.5 | 626.52 | 71.52 | .00 | 1.50 | .00 | 9.78 | 11.28 | 7.500 | 1.561 |
| 2 | 320 | 2 | SL-PA-200 | 200.0 | 160.5 | 10.60 | 143.5 | 626.52 | 71.52 | .00 | 1.50 | .00 | 9.78 | 11.28 | 7.500 | 1.561 |
| 3 | 480 | 2 | SL-PA-200 | 200.0 | 160.5 | 10.60 | 143.5 | 626.52 | 71.52 | .00 | 1.50 | .00 | 9.78 | 11.28 | 7.500 | 1.561 |
| 4 | 640 | 2 | SL-PA-200 | 200.0 | 160.5 | 10.60 | 143.5 | 626.52 | 71.52 | .00 | 1.50 | .00 | 9.78 | 11.28 | 7.500 | 1.561 |
| 5 | 800 | 2 | SL-PA-200 | 200.0 | 160.5 | 10.60 | 143.5 | 626.52 | 71.52 | .00 | 1.50 | .00 | 9.78 | 11.28 | 7.500 | 1.561 |
| 6 | 960 | 2 | SL-PA-200 | 200.0 | 160.5 | 10.60 | 143.5 | 626.52 | 71.52 | .00 | 1.50 | .00 | 9.78 | 11.28 | 7.500 | 1.561 |
| 7 | 1120 | 2 | SL-PA-200 | 200.0 | 160.5 | 10.60 | 143.5 | 626.52 | 71.52 | .00 | 1.50 | .00 | 9.78 | 11.28 | 7.500 | 1.561 |
| 8 | 1280 | 2 | SL-PA-200 | 200.0 | 160.5 | 10.60 | 143.5 | 626.52 | 71.52 | .00 | 1.50 | .00 | 9.78 | 11.28 | 7.500 | 1.561 |
| 9 | 1568 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 10 | 1856 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 11 | 2144 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 12 | 2432 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 13 | 2720 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 14 | 3008 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 15 | 3296 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 16 | 3584 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 17 | 3872 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 18 | 4160 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 19 | 4448 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 20 | 4736 | 1 | SL-BE-360 | 360.0 | 289.0 | 16.30 | 241.9 | 1026.50 | 65.10 | .00 | 2.70 | .00 | 16.14 | 18.84 | 7.500 | 1.572 |
| 21 | 4896 | 3 | SL-TU-200 | 200.0 | 160.5 | 10.50 | 143.7 | 627.22 | 71.60 | .00 | 1.50 | .00 | 10.70 | 12.20 | 7.500 | 1.706 |
| 22 | 5056 | 3 | SL-TU-200 | 200.0 | 160.5 | 10.50 | 143.7 | 627.22 | 71.60 | .00 | 1.50 | .00 | 10.70 | 12.20 | 7.500 | 1.706 |
| 23 | 5216 | 3 | SL-TU-200 | 200.0 | 160.5 | 10.50 | 143.7 | 627.22 | 71.60 | .00 | 1.50 | .00 | 10.70 | 12.20 | 7.500 | 1.706 |
| 24 | 5376 | 3 | SL-TU-200 | 200.0 | 160.5 | 10.50 | 143.7 | 627.22 | 71.60 | .00 | 1.50 | .00 | 10.70 | 12.20 | 7.500 | 1.706 |
| 25 | 5536 | 3 | SL-TU-200 | 200.0 | 160.5 | 10.50 | 143.7 | 627.22 | 71.60 | .00 | 1.50 | .00 | 10.70 | 12.20 | 7.500 | 1.706 |
| 26 | 5696 | 3 | SL-TU-200 | 200.0 | 160.5 | 10.50 | 143.7 | 627.22 | 71.60 | .00 | 1.50 | .00 | 10.70 | 12.20 | 7.500 | 1.706 |
| 27 | 5856 | 3 | SL-TU-200 | 200.0 | 160.5 | 10.50 | 143.7 | 627.22 | 71.60 | .00 | 1.50 | .00 | 10.70 | 12.20 | 7.500 | 1.706 |
| 28 | 6016 | 3 | SL-TU-200 | 200.0 | 160.5 | 10.50 | 143.7 | 627.22 | 71.60 | .00 | 1.50 | .00 | 10.70 | 12.20 | 7.500 | 1.706 |
| 29 | 6112 | 4 | SL-KO-100 | 120.0 | 96.3 | 12.10 | 84.7 | 385.00 | 73.25 | .00 | 1.50 | .00 | 6.61 | 8.11 | 12.500 | 1.717 |
| 30 | 6208 | 4 | SL-KO-100 | 120.0 | 96.3 | 12.10 | 84.7 | 385.00 | 73.25 | .00 | 1.50 | .00 | 6.61 | 8.11 | 12.500 | 1.717 |
| 31 | 6293 | 17 | SC-ST-100 | 106.0 | 85.1 | 11.20 | 75.6 | 311.16 | 67.02 | .00 | 1.59 | .00 | 5.54 | 7.13 | 15.000 | 1.782 |
| 32 | 6378 | 17 | SC-ST-100 | 106.0 | 85.1 | 11.20 | 75.6 | 311.16 | 67.02 | .00 | 1.59 | .00 | 5.54 | 7.13 | 15.000 | 1.782 |
| 33 | 6404 | 21 | SC-ST-000 | 33.0 | 26.5 | 10.00 | 23.8 | 78.84 | 54.55 | .00 | .50 | .00 | 1.40 | 1.90 | 15.000 | 1.782 |
| 34 | 6430 | 21 | SC-ST-000 | 33.0 | 26.5 | 10.00 | 23.8 | 78.84 | 54.55 | .00 | .50 | .00 | 1.40 | 1.90 | 15.000 | 1.782 |
| 35 | 6456 | 21 | SC-ST-000 | 33.0 | 26.5 | 10.00 | 23.8 | 78.84 | 54.55 | .00 | .50 | .00 | 1.40 | 1.90 | 15.000 | 1.782 |
| 36 | 6514 | 5 | SL-AD-100 | 96.0 | 59.0 | 15.80 | 49.7 | 221.28 | 52.63 | .00 | 1.44 | .00 | 3.98 | 5.42 | 15.000 | 1.799 |
| 37 | 6572 | 5 | SL-AD-100 | 96.0 | 59.0 | 15.80 | 49.7 | 221.28 | 52.63 | .00 | 1.44 | .00 | 3.98 | 5.42 | 15.000 | 1.799 |
| 38 | 6630 | 5 | SL-AD-100 | 96.0 | 59.0 | 15.80 | 49.7 | 221.28 | 52.63 | .00 | 1.44 | .00 | 3.98 | 5.42 | 15.000 | 1.799 |
| 39 | 6688 | 5 | SL-AD-100 | 96.0 | 59.0 | 15.80 | 49.7 | 221.28 | 52.63 | .00 | 1.44 | .00 | 3.98 | 5.42 | 15.000 | 1.799 |
| 40 | 6746 | 5 | SL-AD-100 | 96.0 | 59.0 | 15.80 | 49.7 | 221.28 | 52.63 | .00 | 1.44 | .00 | 3.98 | 5.42 | 15.000 | 1.799 |
| 41 | 6778 | 6 | SL-KO-000 | 40.0 | 32.1 | 13.00 | 27.9 | 152.42 | 87.00 | .00 | .50 | .00 | 2.93 | 3.43 | 12.500 | 1.919 |
| 42 | 6810 | 6 | SL-KO-000 | 40.0 | 32.1 | 13.00 | 27.9 | 152.42 | 87.00 | .00 | .50 | .00 | 2.93 | 3.43 | 12.500 | 1.919 |
| 43 | 6842 | 6 | SL-KO-000 | 40.0 | 32.1 | 13.00 | 27.9 | 152.42 | 87.00 | .00 | .50 | .00 | 2.93 | 3.43 | 12.500 | 1.919 |

The output file (Section A.4.2.2 of Appendix 4.2) contains the results of summer and winter for each year of the 1993-2000 period. The output for each season and year is organized according to Steps 1, 2 and 3 described in Section 4.3.1. The last step shows the entire stack of generating units as they are dispatched with progressively less capacity factor and higher variable costs. A sample of that output is reproduced in Exhibit 4-5 to illustrate the source of two pieces of information that will be discussed later in the analysis:

- The production of each unit is obtained from this output and aggregated by plant for use in the financial analysis of revenue requirements.

- The composition of the stack of generating units, the derated capacity of each unit, the forced outage rate, and the variable production cost of each unit are utilized in the development of a table of marginal cost as a function of load level.

## 4.4 ANALYSIS OF SHORT-RUN MARGINAL COSTS

The short-run marginal cost (SRMC) is the cost of supplying one increment of energy without any change in the available capacity of the system. When calculated for a system in dynamic equilibrium between load growth and capacity additions, the SRMC becomes the energy component of the marginal cost of generation and, together with the capacity cost and system losses, constitutes the long-run marginal cost (LRMC), which is discussed in Chapter 7.

The objective of this analysis was to define the SRMC for the pricing periods that were determined through the reliability analysis described above in Section 4.2. The year 1997 was selected as a basis for determining LRMC because it is the year when any pricing policies will begin to impact upon the long-term evolution of the system. The analysis was carried out for 1997 and also for 1993 in order to illustrate any differences between the system today and the anticipated characteristics in 1997.

To determine the SRMC for each of the different pricing periods, it was necessary first to compute the hourly SRMC for an entire week representative of each of the different pricing seasons. The problem was to find a week that is representative of the season in every respect, including average load, peak load, and minimum load. Thus, Section 4.2.1 deals with the selection and adjustment of hourly loads prior to the determination of SRMC.

One of the challenges of the SRMC analysis was to take into account the many different conditions that the generating units may experience at any given time because of planned and forced outages. This aspect is examined in detail in Section 4.2.2.

EXHIBIT 4.5 (Cont.)

SAMPLE RESULTS OF THE DETAILED SIMULATION OF THE GENERATION SYSTEM FOR 1997

| STACK LEVEL MW | LOAD POINT MW | GENERATOR TYPE & NAME | NET RATED MW | P.MAIN. DERATED MW | FORCED OUTAGE % | EFFECTIVE CAPACITY MW | ENERGY OUTPUT GWH | CAPAC. FACTOR % | CAPITAL ANNUITY M$ | FIXED O & M M$ | VARIABLE O & M M$ | FUEL COST M$ | TOTAL COST M$ | FIXED CHARGE $/KW | VARIABLE CHARGE cts/KWH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 44 | 6874 | 6 SL-KO-000 | 40.0 | 32.1 | 13.00 | 27.9 | 152.42 | 87.00 | .00 | .50 | .00 | 2.93 | 3.43 | 12.500 | 1.919 |
| 45 | 6906 | 6 SL-KO-000 | 40.0 | 32.1 | 13.00 | 27.9 | 152.42 | 87.00 | .00 | .50 | .00 | 2.93 | 3.43 | 12.500 | 1.919 |
| 46 | 6938 | 6 SL-KO-000 | 40.0 | 32.1 | 13.00 | 27.9 | 152.42 | 87.00 | .00 | .50 | .00 | 2.93 | 3.43 | 12.500 | 1.919 |
| 47 | 6982 | 28 SC-PO-000 | 56.0 | 45.0 | 12.30 | 39.4 | 153.65 | 62.64 | .00 | .84 | .00 | 2.96 | 3.80 | 15.000 | 1.929 |
| 48 | 7142 | 15 SC-DO-200 | 200.0 | 160.5 | 9.50 | 145.3 | 634.22 | 72.40 | .00 | 1.50 | .00 | 12.61 | 14.11 | 7.500 | 1.988 |
| 49 | 7302 | 15 SC-DO-200 | 200.0 | 160.5 | 9.50 | 145.3 | 634.22 | 72.40 | .00 | 1.50 | .00 | 12.61 | 14.11 | 7.500 | 1.988 |
| 50 | 7462 | 15 SC-DO-200 | 200.0 | 160.5 | 9.50 | 145.3 | 634.22 | 72.40 | .00 | 1.50 | .00 | 12.61 | 14.11 | 7.500 | 1.988 |
| 51 | 7622 | 15 SC-DO-200 | 200.0 | 160.5 | 9.50 | 145.3 | 634.22 | 72.40 | .00 | 1.50 | .00 | 12.61 | 14.11 | 7.500 | 1.988 |
| 52 | 7782 | 15 SC-DO-200 | 200.0 | 160.5 | 9.50 | 145.3 | 634.22 | 72.40 | .00 | 1.50 | .00 | 12.61 | 14.11 | 7.500 | 1.988 |
| 53 | 7942 | 15 SC-DO-200 | 200.0 | 160.5 | 9.50 | 145.3 | 634.22 | 72.40 | .00 | 1.50 | .00 | 12.61 | 14.11 | 7.500 | 1.988 |
| 54 | 8102 | 15 SC-DO-200 | 200.0 | 160.5 | 9.50 | 145.3 | 634.22 | 72.40 | .00 | 1.50 | .00 | 12.61 | 14.11 | 7.500 | 1.988 |
| 55 | 8262 | 15 SC-DO-200 | 200.0 | 160.5 | 9.50 | 145.3 | 634.22 | 72.40 | .00 | 1.50 | .00 | 12.61 | 14.11 | 7.500 | 1.988 |
| 56 | 8630 | 7 SC-KO-500 | 500.0 | 368.5 | 30.00 | 257.9 | 1103.76 | 50.40 | .00 | 6.25 | .00 | 22.02 | 28.27 | 12.500 | 1.995 |
| 57 | 8998 | 7 SC-KO-500 | 500.0 | 368.5 | 30.00 | 257.9 | 1103.76 | 50.40 | .00 | 6.25 | .00 | 22.02 | 28.27 | 12.500 | 1.995 |
| 58 | 9286 | 8 SC-OP-360 | 360.0 | 289.0 | 10.80 | 257.8 | 1093.94 | 69.38 | .00 | 2.70 | .00 | 21.82 | 24.52 | 7.500 | 1.995 |
| 59 | 9574 | 8 SC-OP-360 | 360.0 | 289.0 | 10.80 | 257.8 | 1093.75 | 69.37 | .00 | 2.70 | .00 | 21.82 | 24.52 | 7.500 | 1.995 |
| 60 | 9862 | 8 SC-OP-360 | 360.0 | 289.0 | 10.80 | 257.8 | 1092.45 | 69.28 | .00 | 2.70 | .00 | 21.79 | 24.49 | 7.500 | 1.995 |
| 61 | 10150 | 8 SC-OP-360 | 360.0 | 289.0 | 10.80 | 257.8 | 1088.21 | 69.01 | .00 | 2.70 | .00 | 21.71 | 24.41 | 7.500 | 1.995 |
| 62 | 10438 | 8 SC-OP-360 | 360.0 | 289.0 | 10.80 | 257.8 | 1079.40 | 68.46 | .00 | 2.70 | .00 | 21.53 | 24.23 | 7.500 | 1.995 |
| 63 | 10726 | 8 SC-OP-360 | 360.0 | 289.0 | 10.80 | 257.8 | 1065.85 | 67.60 | .00 | 2.70 | .00 | 21.26 | 23.96 | 7.500 | 1.995 |
| 64 | 10886 | 11 SC-PO-200 | 200.0 | 160.5 | 7.10 | 149.1 | 626.79 | 71.55 | .00 | 1.50 | .00 | 12.52 | 14.02 | 7.500 | 1.997 |
| 65 | 11046 | 11 SC-PO-200 | 200.0 | 160.5 | 7.10 | 149.1 | 620.29 | 70.81 | .00 | 1.50 | .00 | 12.39 | 13.89 | 7.500 | 1.997 |
| 66 | 11206 | 11 SC-PO-200 | 200.0 | 160.5 | 7.10 | 149.1 | 613.33 | 70.02 | .00 | 1.50 | .00 | 12.25 | 13.75 | 7.500 | 1.997 |
| 67 | 11366 | 11 SC-PO-200 | 200.0 | 160.5 | 7.10 | 149.1 | 605.87 | 69.16 | .00 | 1.50 | .00 | 12.10 | 13.60 | 7.500 | 1.997 |
| 68 | 11526 | 11 SC-PO-200 | 200.0 | 160.5 | 7.10 | 149.1 | 597.74 | 68.24 | .00 | 1.50 | .00 | 11.94 | 13.44 | 7.500 | 1.997 |
| 69 | 11686 | 11 SC-PO-200 | 200.0 | 160.5 | 7.10 | 149.1 | 588.71 | 67.20 | .00 | 1.50 | .00 | 11.76 | 13.26 | 7.500 | 1.997 |
| 70 | 11846 | 11 SC-PO-200 | 200.0 | 160.5 | 7.10 | 149.1 | 578.61 | 66.05 | .00 | 1.50 | .00 | 11.56 | 13.06 | 7.500 | 1.997 |
| 71 | 12006 | 11 SC-PO-200 | 200.0 | 160.5 | 7.10 | 149.1 | 567.36 | 64.77 | .00 | 1.50 | .00 | 11.33 | 12.83 | 7.500 | 1.997 |
| 72 | 12166 | 12 SC-RY-200 | 200.0 | 160.5 | 10.80 | 143.2 | 533.01 | 60.85 | .00 | 1.50 | .00 | 11.01 | 12.51 | 7.500 | 2.066 |
| 73 | 12326 | 12 SC-RY-200 | 200.0 | 160.5 | 10.80 | 143.2 | 521.13 | 59.49 | .00 | 1.50 | .00 | 10.76 | 12.26 | 7.500 | 2.066 |
| 74 | 12486 | 12 SC-RY-200 | 200.0 | 160.5 | 10.80 | 143.2 | 509.17 | 58.12 | .00 | 1.50 | .00 | 10.52 | 12.02 | 7.500 | 2.066 |
| 75 | 12646 | 12 SC-RY-200 | 200.0 | 160.5 | 10.80 | 143.2 | 497.65 | 56.81 | .00 | 1.50 | .00 | 10.28 | 11.78 | 7.500 | 2.066 |
| 76 | 12806 | 12 SC-RY-200 | 200.0 | 160.5 | 10.80 | 143.2 | 487.09 | 55.60 | .00 | 1.50 | .00 | 10.06 | 11.56 | 7.500 | 2.066 |
| 77 | 12966 | 12 SC-RY-200 | 200.0 | 160.5 | 10.80 | 143.2 | 477.86 | 54.55 | .00 | 1.50 | .00 | 9.87 | 11.37 | 7.500 | 2.066 |
| 78 | 13126 | 12 SC-RY-200 | 200.0 | 160.5 | 10.80 | 143.2 | 470.18 | 53.67 | .00 | 1.50 | .00 | 9.71 | 11.21 | 7.500 | 2.066 |
| 79 | 13286 | 12 SC-RY-200 | 200.0 | 160.5 | 10.80 | 143.2 | 464.01 | 52.97 | .00 | 1.50 | .00 | 9.58 | 11.08 | 7.500 | 2.066 |
| 80 | 13430 | 14 SC-LZ-200 | 180.0 | 144.5 | 13.40 | 125.1 | 390.27 | 49.50 | .00 | 2.25 | .00 | 8.22 | 10.47 | 12.500 | 2.106 |
| 81 | 13574 | 14 SC-LZ-200 | 180.0 | 144.5 | 13.40 | 125.1 | 387.29 | 49.12 | .00 | 2.25 | .00 | 8.16 | 10.41 | 12.500 | 2.106 |
| 82 | 13718 | 14 SC-LZ-200 | 180.0 | 144.5 | 13.40 | 125.1 | 384.59 | 48.78 | .00 | 2.25 | .00 | 8.10 | 10.35 | 12.500 | 2.106 |
| 83 | 13862 | 14 SC-LZ-200 | 180.0 | 144.5 | 13.40 | 125.1 | 381.89 | 48.44 | .00 | 2.25 | .00 | 8.04 | 10.29 | 12.500 | 2.106 |
| 84 | 13942 | 16 SC-LZ-100 | 100.0 | 80.3 | 16.20 | 67.3 | 209.96 | 47.94 | .00 | 1.25 | .00 | 4.42 | 5.67 | 12.500 | 2.106 |
| 85 | 14022 | 16 SC-LZ-100 | 100.0 | 80.3 | 16.20 | 67.3 | 208.98 | 47.71 | .00 | 1.25 | .00 | 4.40 | 5.65 | 12.500 | 2.106 |
| 86 | 14182 | 9 SC-OS-200 | 200.0 | 160.5 | 11.60 | 141.9 | 437.19 | 49.91 | .00 | 2.50 | .00 | 9.23 | 11.73 | 12.500 | 2.111 |
| 87 | 14342 | 9 SC-OS-200 | 200.0 | 160.5 | 11.60 | 141.9 | 431.31 | 49.24 | .00 | 2.50 | .00 | 9.11 | 11.61 | 12.500 | 2.111 |

EXHIBIT 4.5 (Cont.)

SAMPLE RESULTS OF THE DETAILED SIMULATION OF THE GENERATION SYSTEM FOR 1997

| STACK LEVEL MW | LOAD POINT MW | GENERATOR TYPE & NAME | NET RATED MW | P.MAIN. DERATED MW | FORCED OUTAGE % | EFFECTIVE CAPACITY MW | ENERGY OUTPUT GWH | CAPAC. FACTOR % | CAPITAL ANNUITY M$ | FIXED O & M M$ | VARIABLE O & M M$ | FUEL COST M$ | TOTAL COST M$ | FIXED CHARGE $/KW | VARIABLE CHARGE cts/KWH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 88 | 14420 | 9 SC-OS-200 | 200.0 | 160.5 | 11.60 | 141.9 | 424.15 | 48.42 | .00 | 2.50 | .00 | 8.95 | 11.45 | 12.500 | 2.111 |
| 89 | 14420 | 10 SC-KO-200 | 200.0 | 160.5 | 11.70 | 141.8 | 415.16 | 47.39 | .00 | 1.50 | .00 | 8.76 | 10.26 | 7.500 | 2.111 |
| 90 | 14420 | 10 SC-KO-200 | 200.0 | 160.5 | 11.70 | 141.8 | 405.27 | 46.26 | .00 | 1.50 | .00 | 8.56 | 10.06 | 7.500 | 2.111 |
| 91 | 14420 | 10 SC-KO-200 | 200.0 | 160.5 | 11.70 | 141.8 | 393.94 | 44.97 | .00 | 1.50 | .00 | 8.32 | 9.82 | 7.500 | 2.111 |
| 92 | 14420 | 10 SC-KO-200 | 200.0 | 160.5 | 11.70 | 141.8 | 381.06 | 43.50 | .00 | 1.50 | .00 | 8.04 | 9.54 | 7.500 | 2.111 |
| 93 | 14420 | 10 SC-KO-200 | 200.0 | 160.5 | 11.70 | 141.8 | 366.39 | 41.82 | .00 | 1.50 | .00 | 7.74 | 9.24 | 7.500 | 2.111 |
| 94 | 14420 | 10 SC-KO-200 | 200.0 | 160.5 | 11.70 | 141.8 | 349.56 | 39.90 | .00 | 1.50 | .00 | 7.38 | 8.88 | 7.500 | 2.111 |
| 95 | 14420 | 10 SC-KO-200 | 200.0 | 160.5 | 11.70 | 141.8 | 330.21 | 37.70 | .00 | 1.50 | .00 | 6.97 | 8.47 | 7.500 | 2.111 |
| 96 | 14420 | 10 SC-KO-200 | 200.0 | 160.5 | 11.70 | 141.8 | 308.04 | 35.16 | .00 | 1.50 | .00 | 6.50 | 8.00 | 7.500 | 2.111 |
| 97 | 14420 | 13 SC-J3-200 | 190.0 | 152.5 | 10.70 | 136.2 | 286.21 | 34.39 | .00 | 1.42 | .00 | 6.06 | 7.49 | 7.500 | 2.119 |
| 98 | 14420 | 13 SC-J3-200 | 190.0 | 152.5 | 10.70 | 136.2 | 257.94 | 31.00 | .00 | 1.42 | .00 | 5.46 | 6.89 | 7.500 | 2.119 |
| 99 | 14420 | 13 SC-J3-200 | 190.0 | 152.5 | 10.70 | 136.2 | 227.66 | 27.36 | .00 | 1.42 | .00 | 4.82 | 6.25 | 7.500 | 2.119 |
| 100 | 14420 | 13 SC-J3-200 | 190.0 | 152.5 | 10.70 | 136.2 | 196.36 | 23.60 | .00 | 1.42 | .00 | 4.16 | 5.59 | 7.500 | 2.119 |
| 101 | 14420 | 13 SC-J3-200 | 190.0 | 152.5 | 10.70 | 136.2 | 165.23 | 19.85 | .00 | 1.42 | .00 | 3.50 | 4.93 | 7.500 | 2.119 |
| 102 | 14420 | 13 SC-J3-200 | 190.0 | 152.5 | 10.70 | 136.2 | 135.46 | 16.28 | .00 | 1.42 | .00 | 2.87 | 4.29 | 7.500 | 2.119 |
| 103 | 14420 | 18 SC-LG-100 | 103.0 | 82.7 | 11.90 | 72.8 | 56.93 | 12.62 | .00 | 1.29 | .00 | 1.28 | 2.56 | 12.500 | 2.242 |
| 104 | 14420 | 18 SC-LG-100 | 103.0 | 82.7 | 11.90 | 72.8 | 50.59 | 11.21 | .00 | 1.29 | .00 | 1.13 | 2.42 | 12.500 | 2.242 |
| 105 | 14420 | 18 SC-LG-100 | 103.0 | 82.7 | 11.90 | 72.8 | 44.65 | 9.90 | .00 | 1.29 | .00 | 1.00 | 2.29 | 12.500 | 2.242 |
| 106 | 14420 | 18 SC-LG-100 | 103.0 | 82.7 | 11.90 | 72.8 | 39.14 | 8.68 | .00 | 1.29 | .00 | .88 | 2.17 | 12.500 | 2.242 |
| 107 | 14420 | 18 SC-LG-100 | 103.0 | 82.7 | 11.90 | 72.8 | 34.06 | 7.55 | .00 | 1.29 | .00 | .76 | 2.05 | 12.500 | 2.242 |
| 108 | 14420 | 18 SC-LG-100 | 103.0 | 82.7 | 11.90 | 72.8 | 29.44 | 6.53 | .00 | 1.29 | .00 | .66 | 1.95 | 12.500 | 2.242 |
| 109 | 14420 | 18 SC-LG-100 | 103.0 | 82.7 | 11.90 | 72.8 | 25.27 | 5.60 | .00 | 1.29 | .00 | .57 | 1.85 | 12.500 | 2.242 |
| 110 | 14420 | 19 SC-SI-100 | 105.0 | 84.3 | 11.60 | 74.5 | 21.61 | 4.70 | .00 | 1.31 | .00 | .49 | 1.80 | 12.500 | 2.264 |
| 111 | 14420 | 19 SC-SI-100 | 105.0 | 84.3 | 11.60 | 74.5 | 18.27 | 3.97 | .00 | 1.31 | .00 | .41 | 1.73 | 12.500 | 2.264 |
| 112 | 14420 | 19 SC-SI-100 | 105.0 | 84.3 | 11.60 | 74.5 | 15.34 | 3.34 | .00 | 1.31 | .00 | .35 | 1.66 | 12.500 | 2.264 |
| 113 | 14420 | 19 SC-SI-100 | 105.0 | 84.3 | 11.60 | 74.5 | 12.79 | 2.78 | .00 | 1.31 | .00 | .29 | 1.60 | 12.500 | 2.264 |
| 114 | 14420 | 19 SC-SI-100 | 105.0 | 84.3 | 11.60 | 74.5 | 10.59 | 2.30 | .00 | 1.31 | .00 | .24 | 1.55 | 12.500 | 2.264 |
| 115 | 14420 | 19 SC-SI-100 | 105.0 | 84.3 | 11.60 | 74.5 | 8.71 | 1.89 | .00 | 1.31 | .00 | .20 | 1.51 | 12.500 | 2.264 |
| 116 | 14420 | 22 SC-SK-000 | 45.0 | 36.1 | 10.40 | 32.4 | 3.81 | 1.94 | .00 | .68 | .00 | .09 | .77 | 15.000 | 2.423 |
| 117 | 14420 | 22 SC-SK-000 | 45.0 | 36.1 | 10.40 | 32.4 | 3.43 | 1.74 | .00 | .68 | .00 | .08 | .76 | 15.000 | 2.423 |
| 118 | 14420 | 22 SC-SK-000 | 45.0 | 36.1 | 10.40 | 32.4 | 3.08 | 1.57 | .00 | .68 | .00 | .07 | .75 | 15.000 | 2.423 |
| 119 | 14420 | 24 SC-BL-000 | 41.0 | 32.9 | 10.70 | 29.4 | 2.76 | 1.54 | .00 | .62 | .00 | .07 | .68 | 15.000 | 2.516 |
| 120 | 14420 | 25 SC-HA-000 | 50.0 | 40.1 | 11.80 | 35.4 | 2.44 | 1.11 | .00 | .75 | .00 | .06 | .81 | 15.000 | 2.532 |
| 121 | 14420 | 25 SC-HA-000 | 50.0 | 40.1 | 11.80 | 35.4 | 2.18 | 1.00 | .00 | .75 | .00 | .06 | .81 | 15.000 | 2.532 |
| 122 | 14420 | 25 SC-HA-000 | 50.0 | 40.1 | 11.80 | 35.4 | 1.95 | .89 | .00 | .75 | .00 | .05 | .80 | 15.000 | 2.532 |
| 123 | 14420 | 25 SC-HA-000 | 50.0 | 40.1 | 11.80 | 35.4 | 1.74 | .79 | .00 | .75 | .00 | .04 | .79 | 15.000 | 2.532 |
| 124 | 14420 | 23 SC-J2-000 | 43.0 | 34.5 | 10.40 | 30.9 | 1.57 | .84 | .00 | .64 | .00 | .04 | .69 | 15.000 | 2.684 |
| 125 | 14420 | 23 SC-J2-000 | 43.0 | 34.5 | 10.40 | 30.9 | 1.40 | .74 | .00 | .64 | .00 | .04 | .68 | 15.000 | 2.684 |
| 126 | 14420 | 23 SC-J2-000 | 43.0 | 34.5 | 10.40 | 30.9 | 1.24 | .66 | .00 | .64 | .00 | .03 | .68 | 15.000 | 2.684 |
| 127 | 14420 | 23 SC-J2-000 | 43.0 | 34.5 | 10.40 | 30.9 | 1.09 | .58 | .00 | .64 | .00 | .03 | .67 | 15.000 | 2.684 |
| 128 | 14420 | 23 SC-J2-000 | 43.0 | 34.5 | 10.40 | 30.9 | .96 | .51 | .00 | .64 | .00 | .03 | .67 | 15.000 | 2.684 |
| 129 | 14420 | 23 SC-J2-000 | 43.0 | 34.5 | 10.40 | 30.9 | .85 | .45 | .00 | .64 | .00 | .02 | .67 | 15.000 | 2.684 |
| 130 | 14420 | 23 SC-J2-000 | 43.0 | 34.5 | 10.40 | 30.9 | .75 | .40 | .00 | .64 | .00 | .02 | .67 | 15.000 | 2.684 |
| 131 | 14420 | 27 SC-MI-000 | 50.0 | 40.1 | 11.80 | 35.4 | .64 | .29 | .00 | .75 | .00 | .02 | .77 | 15.000 | 2.759 |

### 4.4.1 Selection and Adjustment of Hourly Loads

There is no single answer to the question of what week must be chosen as representative of a particular season in order to define the SRMC for different pricing periods. The following are some of the most attractive possibilities:

#### Peak Week of the Season

This week has the advantage that it includes the hour of highest demand and therefore will include the highest SRMC of any hour in the season. But there are two major drawbacks: 1) there may be anomalies (holidays) in the week and 2) the mean load of that week will almost always be substantially higher than the mean load of the season.

#### Week that Approximates Seasonal Load Factor

This week has the advantage of being the best approximation to the most representative load pattern during the season. Again, it must be examined for anomalies and it is unlikely that it will bring about the full range of SRMC that may be experienced during the season.

#### Average Week

The average week is made up of hourly loads that correspond to the average of all the hourly loads during that time of the week for all weeks in the season. For example, the hourly load of Monday at noon in the average week is made up of the average of all the loads experienced on Monday at noon in every week of the season. The advantage of this week is that it has "diluted" any anomalies and that it has the average load of the season. On the other hand, it reflects a greater regularity than would be typical of any individual week.

#### Adopted Week

In order to obtain a week of hourly loads representative of each season, the model GPT-L (Generation Planning Tools - Load Analysis Module) was used. The model works as follows:

Step 1 GPT-L examines the historical loads of one year, in this case 1991. It sorts them by season and records the peak load, mean load, base load, and load factor of each week.

EXHIBIT 4.5 (Cont.)

SAMPLE RESULTS OF THE DETAILED SIMULATION OF THE GENERATION SYSTEM FOR 1997

| STACK LEVEL MW | LOAD POINT MW | GENERATOR TYPE & NAME | NET RATED MW | P.MAIN. DERATED MW | FORCED OUTAGE % | EFFECTIVE CAPACITY MW | ENERGY OUTPUT GWH | CAPAC. FACTOR % | CAPITAL ANNUITY M$ | FIXED O & M M$ | VARIABLE O & M M$ | FUEL COST M$ | TOTAL COST M$ | FIXED CHARGE $/KW | VARIABLE CHARGE cts/KWH |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 132 | 14420 | 27 SC-MI-000 | 50.0 | 40.1 | 11.80 | 35.4 | .56 | .26 | .00 | .75 | .00 | .02 | .77 | 15.000 | 2.759 |
| 133 | 14420 | 27 SC-MI-000 | 50.0 | 40.1 | 11.80 | 35.4 | .50 | .23 | .00 | .75 | .00 | .01 | .76 | 15.000 | 2.759 |
| 134 | 14420 | 26 SC-J1-000 | 19.0 | 15.3 | 15.70 | 12.9 | .21 | .26 | .00 | .28 | .00 | .01 | .29 | 15.000 | 2.820 |
| 135 | 14420 | 26 SC-J1-000 | 19.0 | 15.3 | 15.70 | 12.9 | .20 | .24 | .00 | .28 | .00 | .01 | .29 | 15.000 | 2.820 |
| 136 | 14420 | 26 SC-J1-000 | 19.0 | 15.3 | 15.70 | 12.9 | .19 | .23 | .00 | .28 | .00 | .01 | .29 | 15.000 | 2.820 |
| 137 | 14420 | 26 SC-J1-000 | 19.0 | 15.3 | 15.70 | 12.9 | .18 | .21 | .00 | .28 | .00 | .00 | .29 | 15.000 | 2.820 |
| 138 | 14420 | 26 SC-J1-000 | 19.0 | 15.3 | 15.70 | 12.9 | .17 | .20 | .00 | .28 | .00 | .00 | .29 | 15.000 | 2.820 |
| 139 | 14420 | 26 SC-J1-000 | 19.0 | 15.3 | 15.70 | 12.9 | .15 | .19 | .00 | .28 | .00 | .00 | .29 | 15.000 | 2.820 |
| 140 | 14420 | 31 CG-XX-120 | 120.0 | 109.5 | 12.00 | 96.3 | .65 | .12 | 3.07 | .90 | .00 | .03 | 4.00 | 33.064 | 4.637 |
| 141 | 14420 | 31 CG-XX-120 | 120.0 | 109.5 | 12.00 | 96.3 | .46 | .09 | 3.07 | .90 | .00 | .02 | 3.99 | 33.064 | 4.637 |

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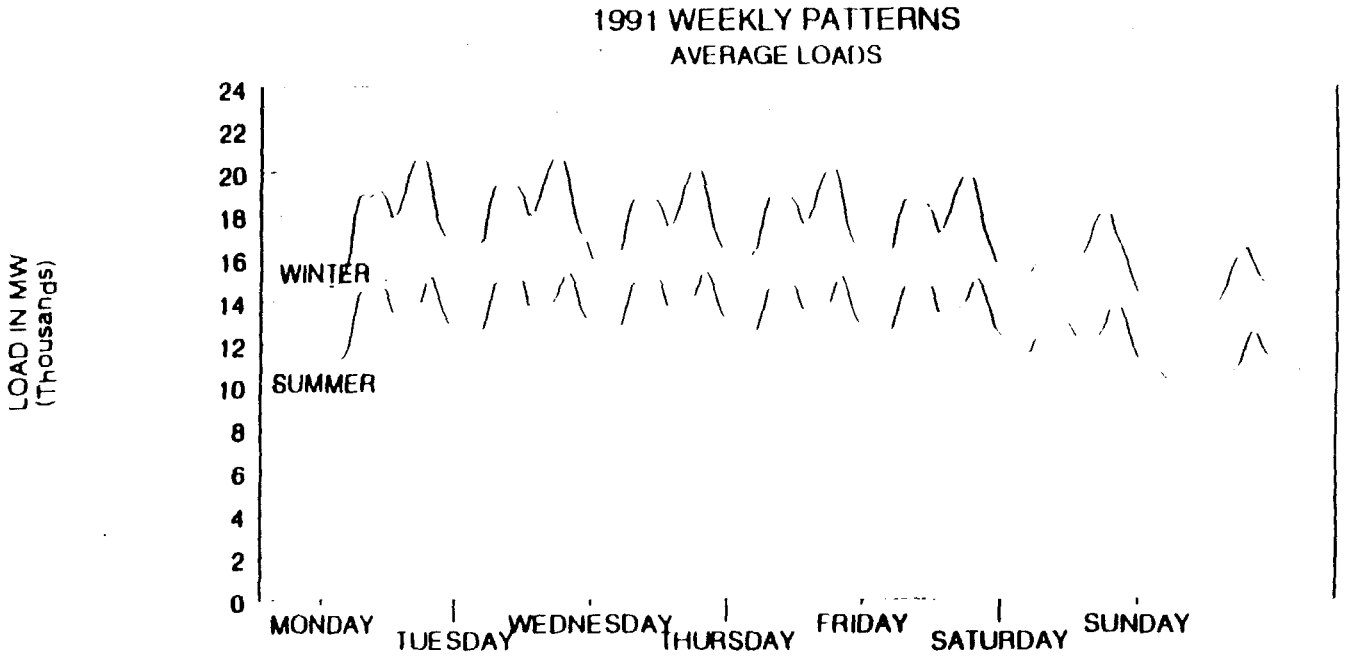
## EXHIBIT 4-6

## 1991 AVERAGE WEEKLY PATTERN



Step 2 GPT-L receives as input, for each season, the peak load, mean load and base load of the target year for SRMC computation. In this case, the target year was 1997 (also 1993).

Step 3 GPT-L receives as input a criterion for week selection in each season. This may be any one of the following: peak week, seasonal load factor week, a particular week designated by the user, or the average week.

Step 4 Based on the selected week (step 3) and the characteristics of the seasonal load of the target year (step 2), GPT-L adjusts the hourly loads of the selected week in such a way that the selected week contains the peak load of that season in the target year and its mean load is equal to the mean load of the season in the target year. Furthermore, the base load of the season in the target year will be somewhat approximated (a closer approximation usually leads to excessive distortion of the weekly pattern).

Step 5 GPT-L stores the hourly loads of both the selected week and the adjusted week for future use; it also calculates and stores the non-dimensional load duration curves for each season.

A detailed output of the model GPT-L for the analysis of the years 1993 and 1997 is shown in Appendix 4.3. In Exhibits 4-6 to 4-8, some relevant results are shown. Exhibit 4-6 shows the average week for winter and summer of the historical year 1991, while Exhibits 4-7 and 4-8 show the adjusted average weeks for each season in the years 1993 and 1997, respectively.

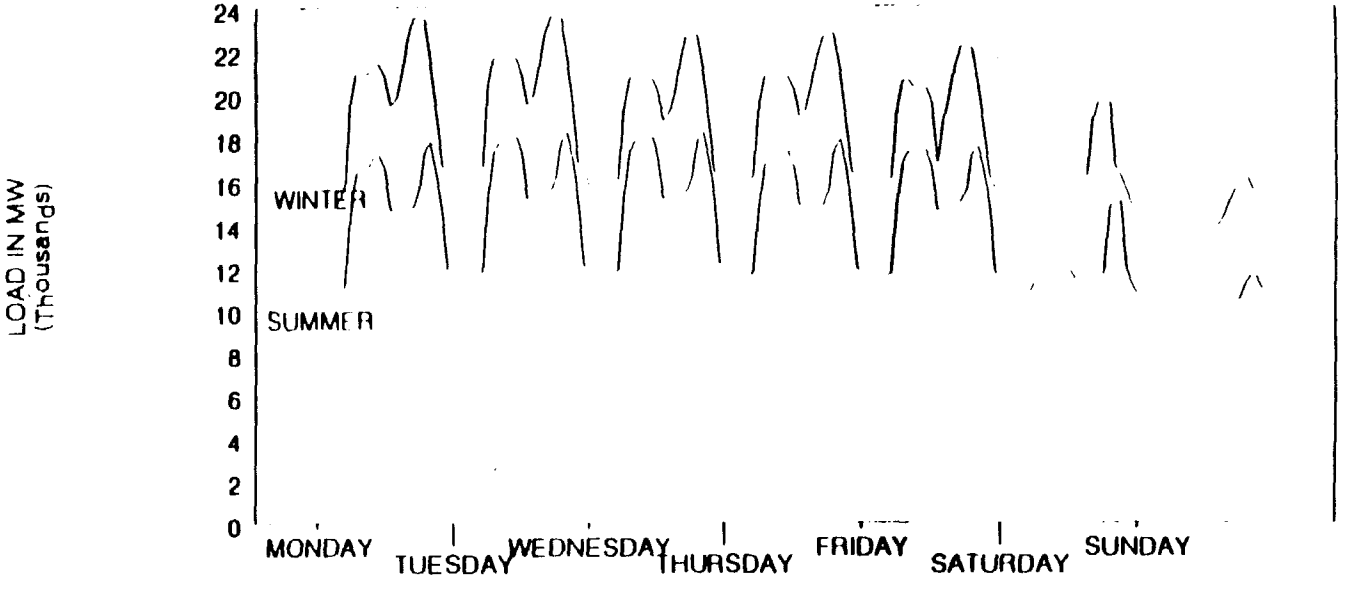
### 4.4.2 Identification of the Generating System

Once a suitable set of hourly loads is selected to represent the loads for the season, then the short-run marginal cost for each hour can be computed.

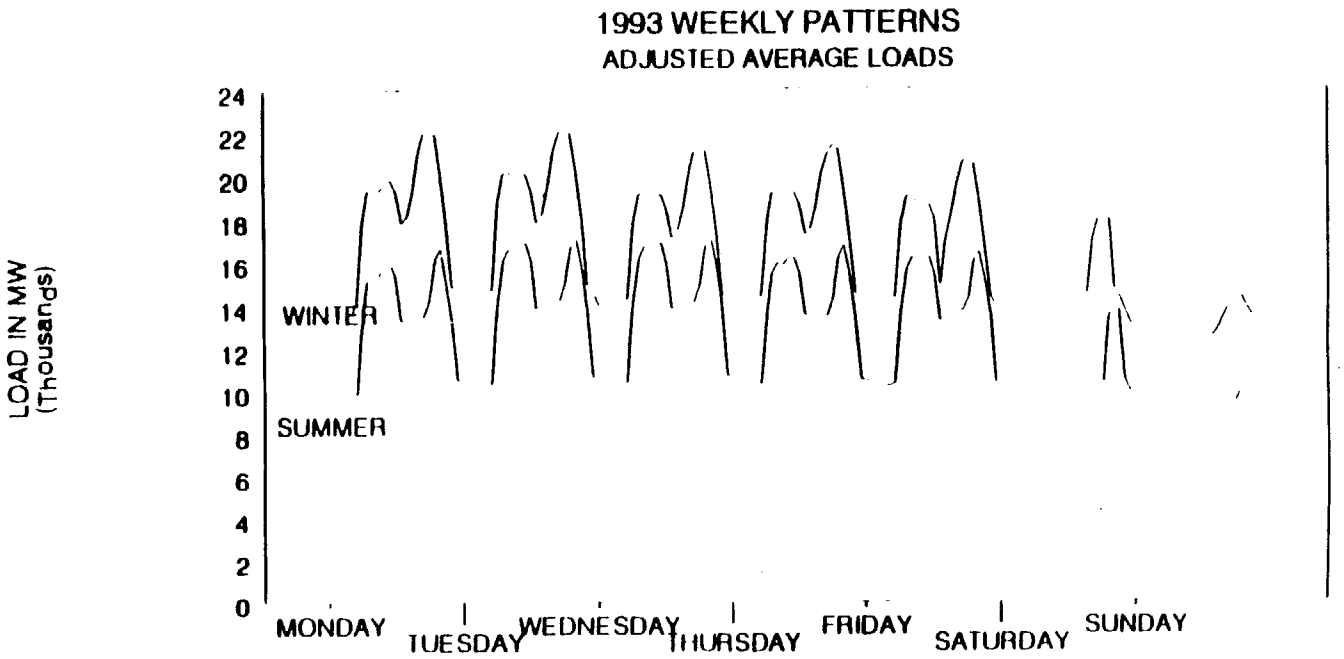
The first step is to identify the generating system that will serve the load during that season. This identification consists of drawing a list, in order of increasing variable production costs, of all the individual generating units that are used to meet the load during that season. The list must include the capacity of the unit, its expected availability (i.e., one minus the probability of outage at any instant during the period), and the variable production cost computed from an economic perspective (that is, using opportunity costs for all variable expenses and not including any taxes or subsidies).

EXHIBIT 4-8

1997 WEEKLY PATTERNS
ADJUSTED AVERAGE LOADS



## EXHIBIT 4-7


1993 WEEKLY PATTERNS
ADJUSTED AVERAGE LOADS
LOAD IN MW
(Thousands)
24
22
20
18
16
14
12
10
8
6
4
2
0
WINTER
SUMMER
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY
SUNDAY

### Hourly Allocation of Expected Marginal Costs

The resources in the stack only include those that are treated as "economically dispatchable" in the simulation. Indeed, these are the only resources that can truly be candidates for marginal production since there are no limitations, other than cost and availability, in their output.

Before the expected short-run marginal cost function can be applied to the hourly loads of the adjusted week, it is necessary to account for the "energy-limited" resources. Both the determination of the expected marginal cost function and the application of the function to the hourly loads are carried out with a computer model that is described below.

### Expected Short-Run Marginal Cost Model GPT-M

The algorithm described in Appendix 4.4 constitutes the logical backbone for the computer model GPT-M (Generation Planning Tools - Marginal Cost Module). The model works as follows:

Step 1 GPT-M will read the stack of "economically dispatchable" generating units and prepare a function of the expected marginal cost of serving a specific load level.

Step 2 GPT-M will read the hourly loads, the capacity and energy available in "energy-limited" units, and the distribution of that energy into base and peak load.

Step 3 GPT-M will reduce all the hourly loads by the base load energy of all energy-limited resources and will then distribute the peak load energy in such a way as to make all loads during the week as uniform as possible.

Step 4 GPT-M will apply the expected marginal cost function (and also the LOLP function developed as an incidental result) to the hourly loads resulting from step 3.

## 4.4.4 Results of the Probabilistic Analysis of Short-Run Marginal Costs

The full output of the GPT-M analysis for the years 1993 and 1997 is presented in Appendix 4.5. In Exhibit 4-9, the expected marginal cost function is shown for both years and Exhibit 4-10 shows the hourly marginal costs for 1993. Exhibit 4-11 presents the average of those hourly marginal costs for 1993 and 1997 for each of the pricing periods recommended in Section 4.2.

In this case, the list or "stack" as it is commonly called, is directly obtained from the simulation of the generation system described in Section 4.3 above. The Polish system is very large and the stack of generating units is fairly long. A sample of the stack of generating units is shown in Exhibit 4.5; the entire stack is available in Appendix 4.2 for each season and year in the period 1993-2000.

### 4.4.3 Computation and Allocation of Short-Run Marginal Cost

As mentioned above, one major issue is that the system may exist in any of many different conditions because of planned and forced outages. Planned outages are relatively easy to account for by either eliminating from a season those resources that will be largely out of service or, more commonly, by derating (i.e., reducing) the capacity of each resource in proportion to the time when it will be undergoing maintenance.

Forced outages, on the other hand, are a difficult problem. The traditional approach is to dispatch the stack of generating units under the load of each hour and register the unit that is at the level of the hourly load. This unit is said to be "at the margin," meaning that any increment in load will result in an incremental or marginal production from that unit. To account for forced outages, the process is repeated many times. This allows the units in the stack to be randomly present or absent in such a way that, on average, the ratio between the times when any individual unit was absent to the total times the process was repeated is close to the forced outage rate of that unit. This approach is commonly called a "Monte-Carlo" approach due to the analogy between random draws and casino gambling.

At Hagler, Bailly, a different approach was developed to yield a purely analytical and exact solution that is closely linked to the convolution theorem mentioned in Section 4.3 for the computation of loss of load probability (LOLP). Indeed, the recursive equation that constitutes the basis of the analytical approach uses as an intermediate step the convolution equation used for LOLP computation. A full description of this method requires some background on probability mathematics; a detailed description is presented in Appendix 4.4. The end result, however, is a simple relationship between the expected (i.e., the weighted average of the outcome of all possible system conditions weighted by their respective probabilities) marginal cost as a function of the load level to be served.

EXHIBIT 4-10

HOURLY MARGINAL COST PATTERN

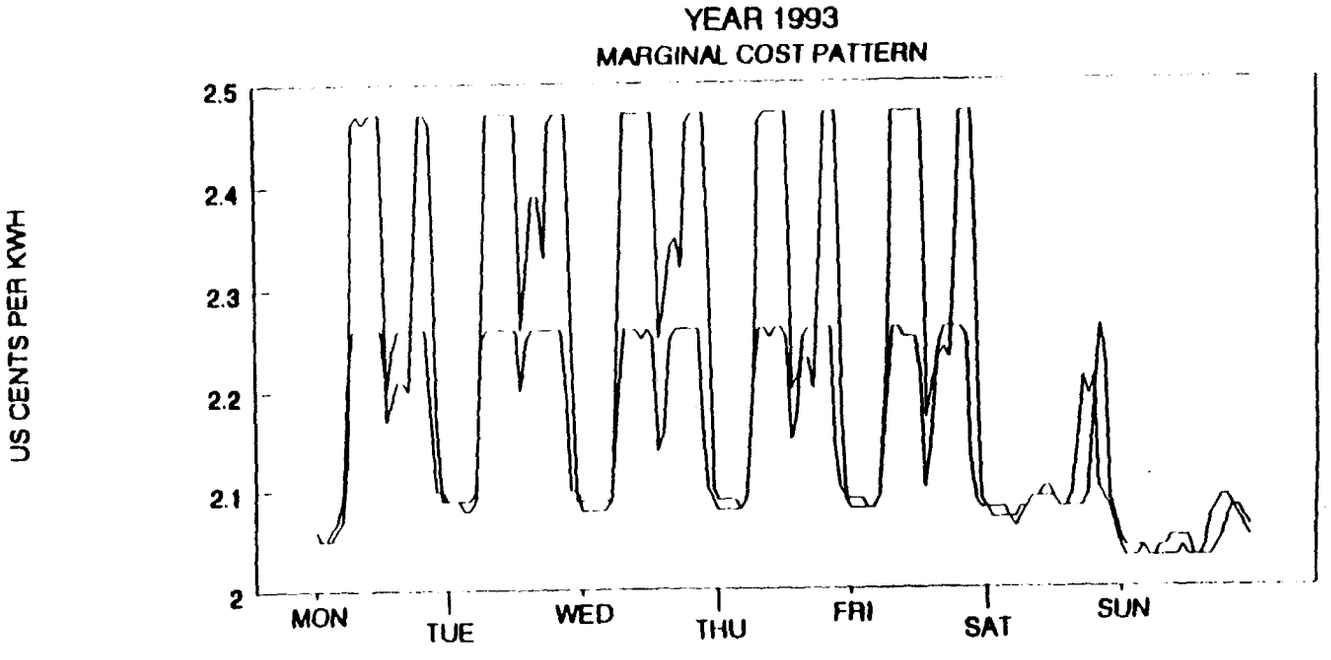


**Exhibit 4-11**
**Probabilistic Analysis Short-Run Marginal Costs (US Cents/kWh)**

1997

| | Winter | Summer | Average |
|---|---|---|---|
| Morning Peak | 2.20 | 2.45 | 2.33 |
| Evening Peak | 2.24 | 2.46 | 2.35 |
| Off-Peak | 2.07 | 2.12 | 2.10 |

These results for the generation system were used to develop the LRMC structure, which was in turn used in shaping bulk and retail tariff revenues. This analysis is described in Chapter 7.

### 4.4.5 Dispatch Constraints

The probabilistic analysis described above provides a very accurate structure of short run marginal costs when the generation system has adequate (i.e. close to least cost) proportions of peaking, intermediate load and base load units. However, the Polish power system does not have now and will not have achieved by 1997 such optimum generation mix but will have excessive base load capacity and insufficient peaking capacity.

When a generation system has insufficient peaking capacity it may be necessary to carry excess capacity in operation or as spinning reserve during the off-peak hours in order to have that capacity available to meet the higher loads of the peak period. This constraint results in increased cost during the off-peak hours and apparently lower costs during the peak hours. The analysis carried out above is correct as far as depicting the true marginal cost of off-peak operation but it underestimates the marginal cost of peaking operation by not accounting for the additional off-peak cost incurred to be able to meet peak loads.

An approximation to the additional marginal cost of a peaking operation with insufficient peaking capacity can be obtained by allocating to the peak hours the difference between peak and off-peak marginal costs as shown through the following formula:

$$AMCp = (MCp - MCb) \times (168-P)/P$$

where:
AMCp = additional cost of peaking operation
MCp = apparent marginal cost of peaking operation
MCb = marginal cost of normal base operation
P = hours of peaking operation

This approximation presumes a correspondence between marginal and average production costs that does not really exist in practice and the adjustment is just as likely to overestimate or underestimate the true marginal cost of peaking under dispatch constraints. Nevertheless, used carefully, it provides an adequate rationale for the purposes of tariff structure.

By 1997 it is expected that there will be a modest amount of gas turbine capacity in the system and, considering the dispatch constraints described above, it is likely that they will be at the margin at least during the evening peak. Therefore, it was decided to apply the adjustment above to the lower (morning) peak and to assume that the gas turbines will be at the margin during evening peak hours.

Based on these assumptions the marginal costs of Exhibit 4-11 are adjusted as shown in Exhibit 12.

**Exhibit 4-12**

**Adjusted Short-Run Marginal Costs (US Cents/kWh)**

| | WINTER | SUMMER | AVERAGE |
|---|---|---|---|
| Morning Peak | 2.80 | 3.97 | 3.39 |
| Evening Peak | 4.64 | 4.64 | 4.64 |
| Off-Peak | 2.07 | 2.12 | 2.10 |

## 4.5 MARGINAL COST AND AVOIDED COST

It may be useful to close this chapter with a brief discussion of the relationships between Short Run Marginal Costs, Long Run Marginal Costs and Avoided Costs since these three concepts are linked by alternative methods of computing marginal energy costs.

### 4.5.1 Average Incremental Revenue Requirements

The Short Run Marginal Cost discussed above is, by definition, only the marginal cost of energy since the SRMC is the cost of producing an increment of power with the same capacity. In Chapter 7, the SRMC is then combined with an independent estimate of the marginal cost of capacity to obtain the Long Run Marginal Cost (LRMC) of the system.

As will be further discussed during the determination of LRMC, it is possible to obtain the marginal cost of capacity and energy simultaneously by using a method known as the Average Incremental Revenue Requirements (AICR). The process consists, very briefly, of calculating the annual fixed and variable costs of two least cost expansion plans. The first corresponds to a base case load growth, the second to a higher load growth, often obtained by advancing all load levels by one year. Long run capacity and energy costs are then obtained by allocating all incremental fixed costs to the increments of capacity and all variable costs to the increments of energy.

Since the least cost expansion of the system seeks a compromise between low investment and low operating costs it is inevitable that some of the incremental fixed costs are not solely derived from the need of incremental capacity but result from the need to lower operating costs and thus are truly energy costs. The AICR method thus needs to include this correction. The AICR method has not been used in this study to determine marginal costs because current excess reserve during the short term and low load growth makes it difficult to measure incremental costs. However, a related method was used to estimate the economic avoided cost of non-disptachable resources as described below.

### 4.5.2 Differential Revenue Requirements

As will be discussed in Chapter 6 it is often desirable to determine the value of a resource to the generation system without reference to its own production cost. This is normally done by computing the cost of expanding the system with and without the resource in question and then allocating differential fixed costs to capacity and differential variable costs to energy. The

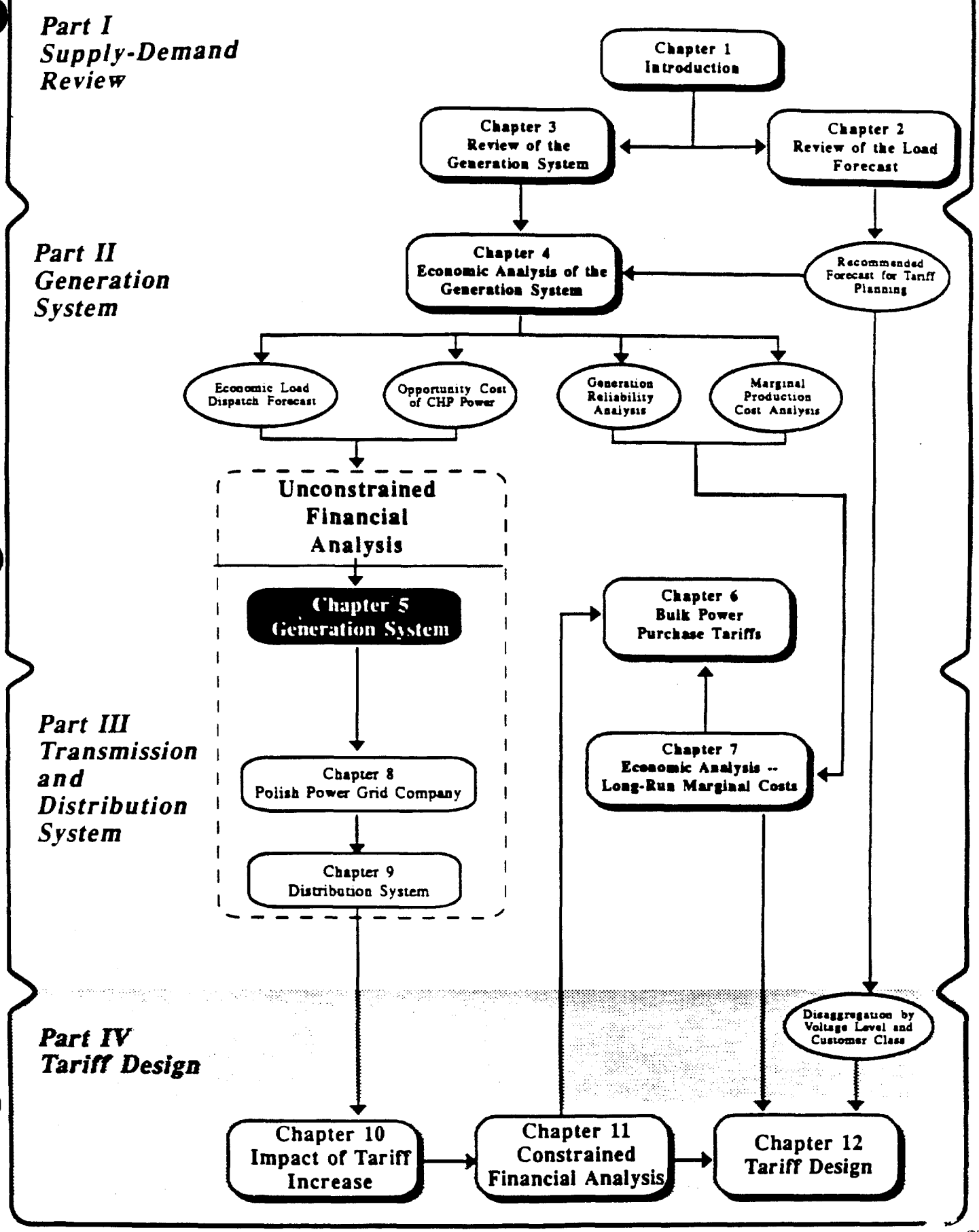
process, known as Differential Revenue Requirements (DRR) method sounds very similar to the AICR method described above to compute marginal costs.

Clearly, the cost of serving a small increment of load (AICR) is related to the cost of replacing a small decrement of resources (DRR). However, in the case of the AICR the increment of load has the system load factor whereas in the case of the DRR for the purpose of avoided cost computation the decrement of resources is equivalent to the addition of an increment of load but the equivalent load factor would be the capacity factor of the replaced resource.

Therefore, if a resource is very small and its capacity factor is similar to the system load factor then the avoided cost of the resource should be similar to the marginal cost of the system.

In Chapter 6 the DRR method will be used to estimate the avoided cost of non-dispatchable resources in the Polish power system.

# Road Map to the Study



# CHAPTER 5: UNCONSTRAINED FINANCIAL ANALYSIS OF THE GENERATION SYSTEM

## 5.1 OBJECTIVES AND APPROACH

This chapter presents the results of an analysis of the financial performance and future financial revenue requirements of the Polish generating system. The objective of this analysis was to forecast the revenues that must be collected by the generating plants in order to operate according to an acceptable criterion of financial performance. Its results were used to develop bulk transfer prices from generating companies to PPGC based on the long-run marginal cost structure for the entire system (Chapter 7).

It is important to stress here that the financial forecast developed in this chapter corresponds to a scenario of ***unconstrained*** tariff increase and instant asset revaluation. In Chapter 11, these results are subjected to different assumptions in order to arrive at a financial forecast that is constrained by the need to limit the impact of tariff increases and by a feasible extent of and schedule for the revaluation of assets.

The approach to this analysis was first to perform an historical review of the financial data, followed by the adoption of a financial criterion to be met. Last, the forecast revenue requirements were determined.

## 5.2 HISTORICAL FINANCIAL REVIEW AND ANALYSIS

The financial analysis of the generating system is based on a detailed analysis of 17 individual plants consisting of Poland's four largest lignite-fired conventional grid plants and 13 of the largest coal-fired conventional and collector grid plants. This sample covers 96 percent of all the energy generated by grid plants.

A considerable effort was made by PPGC, at the consultants' request, to gather the historical financial data for each of the generating plants. These data were used to develop a financial spreadsheet model for each generating plant for the years 1990 and 1991. The purpose of this exercise was to provide a valid starting position for future projections, as well as to attempt to identify any underlying trends and ratios that might be expected to continue into the future.

While distortions in data due to high inflation (600 percent for 1990 and over 50 percent in 1991) cannot be entirely eliminated from the analysis, a number of clear conclusions emerge from the historical data. These relate to the valuation of assets, debt-to-equity ratios, and expenses of the generating plants.

### 5.2.1 Asset Valuation

The valuation of gross fixed assets as of December 31, 1991 was based on a revaluation undertaken by the Polish Statistical Office in 1990. This revaluation, as will be discussed later in greater detail, still leaves the assets significantly undervalued with respect to their probable replacement cost. It thus exaggerates the stated rate of return as well as the stated debt-to-equity ratio.

### 5.2.2 Debt-to-Equity Ratio

As of December 31, 1991, the long-term debt of the Polish generation system amounted to 2,654 B.Zl (1 B.Zl = 1 billion Zlotys = 1,000,000,000 Zlotys), most of which is associated with the relatively new Belchatow lignite plant. This debt is 7.3 percent of the stated (and greatly undervalued) equity of 36,567 B.Zl.

### 5.2.3 Expenses

It is apparent that significant efforts have already been made to maintain (or even increase in real terms) powerplant revenues in line with inflation. In particular, revenues have been well adjusted for rising variable energy costs (coal and lignite purchase costs, and environmental penalties).

On the other hand, overhead costs have not been fully passed through. This would be even more apparent if the assets (and hence, depreciation expense) had been revalued in line with inflation.

## 5.3 ADOPTED CRITERIA, ASSUMPTIONS AND DATA SOURCES

### 5.3.1 Financial Criteria

Based on the Polish Government's stated policy to establish power generation as a viable commercial enterprise, a profit-driven financial criterion has been adopted: the generating plants must achieve an annual rate of return of 6.0 percent on their net assets employed. (The 6.0% criterion represents a judgment which relates to industry risk and country risk, and which compares for example, to a 4.0% return for electricity generation in the UK, 6.0% in Egypt and 8.0% in certain African countries).

For this purpose, the rate of return is defined as "operating income after depreciation expense and before financial expense and income tax," as a ratio of "revalued net fixed assets plus accounts receivable and inventories (taken as an average for the year)."

The revalued net assets are based on 1992 price levels. Accumulated depreciation is also adjusted to 1992 price levels and based on the remaining useful life of the assets (assuming a total 30-year economic life).

While other financial performance criteria would normally be relevant, the financial strength of the Polish generating system and its relatively limited projected capital expenditure requirements, render other ratios of little significance if the target 6.0 percent rate of return on revalued net assets is achieved.

### 5.3.2 Assumptions

The key assumptions used in the financial analysis are listed below:

- All values are projected at mid-1992 price levels and the corresponding exchange rate of 13,400 Zl equals US $1.00.

- Fuel cost (including transportation) is projected at the economic prices for coal and lignite discussed in Chapter 3, equivalent to 29.970 Zl/KJ (Zloty per kilojoule) of coal.

- The gross value (before depreciation) of the system generating assets is assumed to be out of date by a factor of 6.0. This assumption results from the ratio between the estimated 1992 international price of comparable coal-fired plants[1] and the average 1991 gross book value of the generating assets.

- The net value of each asset is based on applying the uniform index of 6.0 to its gross book value and calculating the accumulated depreciation from its commissioning date, assuming an economic life of 30 years.

- It is assumed that 15 percent of the target rate of return is achieved through energy sales and 85 percent of the target rate of return is collected through capacity sales. This assumption has been made in order to provide a profit-incentive to each generating plant to actually produce electricity, rather than being able to earn all its net income solely by being available for dispatch.

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[1] Based on $870/kW for a coal-fired plant without emission control equipment and before interest during construction.

### 5.3.3 Sources of Data

#### Income Statement

The sources for the historical data for each plant's income statement were the "F-02" annual accounting returns for each plant, the Energy Statistics reports from CEI, and energy purchase analyses provided by PPGC.

For 1992 and future years, the sources used for each plant are briefly outlined as follows:

- Physical energy sales and production were developed for each plant using the simulation discussed in Chapter 4 (details are reported in Appendix 4.2).

- Environmental charges were based on the PPGC energy purchase summary by plant for January-August 1992.

- Operation and maintenance costs were considered as fixed costs and several sources of data were used:

  -- 1991 actual costs adjusted by inflation to 1992 and 1993

  -- estimates for 1992 established by Energoprojekt's detailed cost analysis

  -- international comparisons and trends for plants of various sizes as used in the economic analysis presented in Chapter 4.

  In general, the approach taken was to base personnel costs for 1992 and 1993 on the 1991 actual increased by inflation, and to use Energoprojekt's assessment for maintenance and other overhead. Then, if the resulting O&M level exceeded the economic standard, the total O&M estimate was reduced by 10 percent per year until it reached the economic standard, which was usually met by 1995.

- Interest expense (income) was assumed to be earned on net cash balances. The only plant with significant interest expense is Belchatow.

- Corporate tax was assumed to continue at the current rate of 40 percent.



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### Balance Sheet

The sources for the historical data for each plant's balance sheet were the "F-02" annual accounting returns for each plant, together with the 1991 fixed-asset valuations contained in the May/June 1992 cost analysis prepared by the Tariffs and Economics Department of PPGC.

The historical data provided information with respect to historical working capital requirements (for example, days' sales in accounts receivable, or days' supply of fuel on hand), which were then used to project future working capital requirements.

The critical balance sheet item, however, is fixed assets - gross and net. In addition to the revaluation and amortization assumptions discussed above, provision has been made for additions to fixed assets resulting from rehabilitation and investment in environmental protection over the 1993-1997 period. The level of investment for each plant is based on the review discussed in Chapter 3.

## 5.4 RESULTS

The results presented below are those for the unconstrained tariff increase and instant asset revaluation scenario. See Chapter 11 for results under the financial forecast constrained by the need to limit the impact of tariff increases and the feasible extent of and schedule for the revaluation of assets.

### 5.4.1 Results for the Consolidated Generating System

The revenue requirement in 1994 for the consolidated generating system, expressed at 1992 price levels, is 489 Zl/kWh. This results from an average fixed charge of 97,709,000 Zl/kW-M (Zloty per kW per month) and an average variable charge of 307 Zl/kWh. The income statement, balance sheet, and operating and financial ratios for the consolidated system are shown in Exhibits 5.1a, 5.1b and 5.1c, respectively.

On the basis of a 6.0 percent return on net assets revalued to 1992 levels -- which (after an average 40 percent tax rate) is equivalent to about 4.5 percent after tax on revalued equity -- the total system (as now constituted) should generate approximately 30,000 B.Zl in surplus cash by 1997. This cash balance includes the projected rehabilitation and modernization of existing plants, but it does not include financing for the Opole powerplant, which is under construction. Financing for this plant is assumed to be paid by Government equity contributions.

## ...bit 5

## INCOME STATEMENT – CONSOLIDATED GENERATION SYSTEM

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | 97,847 | Energy Sales -- Gwh | 97,011 | 96,337 | 99,676 | 102,424 | 105,582 | 107,948 |
| | | 20,773 | Capacity -- MW | 20,476 | 20,366 | 20,180 | 20,390 | 20,189 | 21,316 |
| | | | % Capacity Sold | | | | | | |
| | | 73,135 | Hours of Production/Year | 73,626 | 73,626 | 74,765 | 75,904 | 66,791 | 60,630 |
| | | 195,312 | Capacity Sales - Mw/m | 185,803 | 182,381 | 184,205 | 184,127 | 172,483 | 173,497 |
| | | | Max Capacity Sales @1994 Installation | 208,851 | 207,732 | 202,166 | 200,636 | 191,242 | 195,389 |
| | | 115,499 | Energy Sales Price -- Zl/Kwh | 196,754 | 300,222 | 306,771 | 313,057 | 326,149 | 338,126 |
| | | 45,459 | Capacity Price -- '000 Zl/Mw/m | 53,884 | 103,053 | 96,580 | 96,867 | 100,644 | 103,333 |
| | | | Adjusted 1994 Capacity Price | | | | | | |
| | | | Sales Revenue | | | | | | |
| | | 11,301 | Energy | 19,087 | 28,922 | 30,576 | 32,064 | 34,435 | 36,500 |
| | | 8,879 | Capacity | 10,012 | 18,795 | 18,159 | 17,836 | 17,359 | 17,928 |
| 282 | 3,696 | 20,199 | Sub-total Electricity Sales | 29,099 | 47,717 | 48,737 | 49,900 | 51,795 | 54,428 |
| 18 | 320 | 412 | Others | 1,012 | 885 | 875 | 875 | 875 | 855 |
| 300 | 4,016 | 20,611 | **Total Sales/Revenues** | 30,111 | 48,602 | 49,611 | 50,775 | 52,669 | 55,283 |
| | | | **Variable Cost** | | | | | | |
| 170 | 2,087 | 10,738 | Fuel | 11,592 | 25,295 | 26,245 | 27,016 | 28,018 | 28,757 |
| | 88 | | Transport | 1,694 | | | | | |
| | 49 | 601 | Environmental Penalty | 2,719 | 2,687 | 2,742 | 2,798 | 2,850 | 2,871 |
| 3 | 28 | 4 | Others | | | | | | |
| 173 | 2,253 | 11,343 | Total Variable Cost @ 1992 Prices | 16,004 | 27,982 | 28,987 | 29,815 | 30,868 | 31,628 |
| | | | Plus: Inflation | | | | | | |
| 172 | 2,236 | 11,343 | **Total Variable Cost** | 16,004 | 27,982 | 28,987 | 29,815 | 30,868 | 31,628 |
| | | | **Fixed/ Capacity Costs** | | | | | | |
| 95 | 951 | 5,865 | Existing Plant | 6,398 | 5,778 | 5,342 | 4,956 | 4,695 | 4,501 |
| | | | New Plant | | | 72 | 145 | 269 | 434 |
| 95 | 951 | 5,865 | Total Fixed Cost (ex Dep'n)@1992 | 6,398 | 5,778 | 5,415 | 5,101 | 4,964 | 4,935 |
| | | | Plus: Inflation | | | | | | |
| 95 | 951 | 5,865 | **Total Fixed Cost before Dep'n.** | 6,398 | 5,778 | 5,415 | 5,101 | 4,964 | 4,935 |
| 7 | 141 | 1,947 | Depreciation Expense | 6,953 | 6,953 | 6,801 | 9,434 | 9,719 | 11,027 |
| 274 | 3,344 | 19,155 | Total Operating Expense | 31,355 | 42,714 | 43,203 | 44,349 | 45,571 | 47,590 |
| 27 | 691 | 1,456 | Operating Income | (1,244) | 5,888 | 6,408 | 6,426 | 7,099 | 7,693 |
| 4 | 31 | 65 | Financial/Interest Expense (Net) | (557) | (1,199) | (1,761) | (2,347) | (2,960) | (3,699) |
| 0 | (67) | 421 | Extraordinary Income (Loss) | | | | | | |
| 22 | 588 | 1,799 | Income Before Tax | (687) | 7,087 | 8,169 | 8,772 | 10,079 | 11,392 |
| 5 | 279 | 980 | Corporate Tax | (275) | 2,835 | 3,268 | 3,509 | 4,031 | 4,557 |
| 17 | 309 | 820 | Net Income After Tax | (412) | 4,252 | 4,901 | 5,263 | 6,047 | 6,835 |

Billions Zloty at Base Year Prices

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## Exhibit 5-1b
## BALANCE SHEET – CONSOLIDATED GENERATION SYSTEM

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **ASSETS** | | | | | | |
| | 544 | 723 | Cash | 879 | 1,288 | 1,304 | 1,292 | 1,282 | 1,274 |
| | 374 | 1,378 | Accounts Receivable | 1,613 | 2,480 | 2,602 | 2,732 | 2,958 | 3,180 |
| | 797 | 1,614 | Inventories -- Fuel | 1,694 | 3,171 | 3,334 | 3,414 | 3,547 | 3,630 |
| | 12 | 20 | Others | | | | | | |
| | 468 | 224 | Others | | 450 | 850 | 1,300 | 1,700 | 2,000 |
| | 2,196 | 3,959 | Total Current Assets | 4,186 | 7,390 | 8,090 | 8,738 | 9,488 | 10,084 |
| | 35,125 | 36,835 | Gross Fixed Assets | 219,816 | 219,832 | 238,904 | 247,856 | 267,422 | 297,728 |
| | 16,435 | 18,295 | Less: Acc. Depreciation | 122,397 | 131,351 | 140,152 | 149,585 | 159,304 | 170,331 |
| | 18,690 | 18,539 | Net Fixed Assets | 97,418 | 88,481 | 98,752 | 98,270 | 108,118 | 127,397 |
| | 1,413 | 18,735 | Capital Work-in-Progress | 23,133 | 33,446 | 27,611 | 30,368 | 26,257 | 9,738 |
| | 22,299 | 41,233 | TOTAL ASSETS EMPLOYED | 124,737 | 129,317 | 134,453 | 137,376 | 143,862 | 147,219 |
| | | | **LIABILITIES** | | | | | | |
| | 602 | 1,329 | Accounts Payable | | | | | | |
| | 556 | 920 | Other Liabilities | | | | | | |
| | | | LTD due within 1 year - existing | 170 | 170 | 170 | 170 | 170 | 170 |
| | 10 | 18 | LTD due within 1 year - new local | | | | | | |
| | | | LTD due within 1 year - new FX | | | | | | |
| | | | Cash Deficiency (Surplus) | (5,911) | (9,397) | (13,159) | (18,739) | (23,671) | (30,489) |
| | 1,168 | 2,268 | Total Current Liabilities | (5,741) | (9,227) | (12,989) | (18,569) | (23,502) | (30,319) |
| | (50) | | Other Liabilities | 704 | 1,970 | 3,342 | 4,112 | 6,934 | 7,725 |
| | 1,447 | 2,492 | Long Term Debt - existing | 3,068 | 2,899 | 2,729 | 2,559 | 2,390 | 2,220 |
| | | 162 | Long Term Debt - new local | 704 | 1,970 | 3,342 | 4,112 | 6,934 | 7,725 |
| | | | Long Term Debt - new FX | | | | | | |
| | | | Total Long Term Debt | 3,772 | 4,869 | 6,071 | 6,671 | 9,323 | 9,945 |
| | | | **Equity Balance:** | | | | | | |
| | 14,657 | 15,642 | Assumed Opening Position | 32,770 | 32,770 | 32,770 | 32,770 | 32,770 | 32,770 |
| | 1,199 | 16,751 | Additional Paid in Capital | 2,718 | 5,436 | 8,230 | 10,870 | 13,589 | 16,306 |
| | 482 | 378 | Revaluation of Fixed Assets | 87,832 | 87,832 | 87,832 | 87,832 | 87,832 | 87,832 |
| | 2,833 | 3,103 | Retained Earnings -- Prior Years | 3,797 | 3,385 | 7,637 | 12,539 | 17,802 | 23,849 |
| | 507 | 694 | Current Year's Net Income | (412) | 4,252 | 4,901 | 5,263 | 6,047 | 6,835 |
| | 19,678 | 36,567 | Total Equity | 126,706 | 133,676 | 141,371 | 149,275 | 158,041 | 167,593 |
| | 22,299 | 41,233 | TOTAL LIABILITIES & EQUITY | 124,737 | 129,317 | 134,453 | 137,376 | 143,862 | 147,219 |

Billions Zloty at Base Year Prices

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## Exhibit 5-1c
## OPERATING AND FINANCIAL RATIOS – CONSOLIDATED GENEARATION SYSTEM

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES** | | | | | | |
| | | | Energy Sales (Gwh) - Annual Growth % | -0.9% | -0.7% | 3.5% | 2.8% | 3.1% | 2.2% |
| | 1209.5% | 446.2% | Sales Revenue (Zl) - Annual Growth - % | 44.1% | 64.0% | 2.1% | 2.4% | 3.8% | 5.1% |
| | | 206.433 | Average Tariff - - Zlotys/kwh | 299.957 | 495.317 | 488.951 | 487.195 | 490.566 | 504.206 |
| | | | **OPERATING RATIOS** | | | | | | |
| | | 115.929 | Variable Cost / kwh | 164.969 | 290.460 | 290.815 | 291.091 | 292.358 | 292.992 |
| | | 174.048 | Total Operating Cost/ kwh | 289.863 | 398.883 | 394.636 | 396.005 | 391.496 | 409.362 |
| | | 174.715 | Total Cost/ kwh (excl. ROE) | 284.118 | 386.439 | 376.969 | 373.094 | 363.271 | 375.094 |
| | | 30.027 | Fixed Cost/ Mw/m | 34.434 | 31.684 | 29.395 | 27.702 | 28.898 | 28.445 |
| | | 39.994 | Fixed Cost plus Dep'n/ Mw/m | 82.621 | 80.775 | 77.175 | 78.937 | 85.243 | 92.000 |
| | | 40.328 | Fixed Cost plus Dep'n & Int./Mw/m | 79.622 | 74.202 | 67.615 | 66.192 | 67.966 | 70.679 |
| | 17.2% | 7.1% | Operating Income to Sales - % | -4.1% | 12.1% | 12.9% | 12.7% | 13.5% | 13.9% |
| | | | Operating Income to Gross Assets in Service (Average) - %: | | | | | | |
| | | 14.9% | -historical | | | | | | |
| | 3.9% | 4.0% | -revalued | -1.0% | 2.7% | 2.8% | 2.6% | 2.8% | 2.7% |
| | 7.4% | 7.8% | Operating Income/ Net Assets - % | -2.1% | 6.3% | 6.8% | 6.5% | 6.9% | 6.5% |
| | | | **BALANCE SHEET RATIOS** | | | | | | |
| | | 1.7 | Current Ratio | -0.7 | -0.8 | -0.6 | -0.5 | 0.4 | 0.3 |
| | | 0.4 | Cash at Bank to Sales - months | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| | | 24 | Accts Receivable to Sales - days | 20 | 19 | 19 | 20 | 21 | 21 |
| | | | Debt to Equity Ratio - % | | | | | | |
| | | | -historical | | | | | | |
| | | 0.0% | -revalued | 3.0% | 3.6% | 4.3% | 4.5% | 5.9% | 5.9% |

Billions Zloty at Base Year Prices
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It is relevant to observe that total expenditure on Opole (in 1992 prices) will amount to approximately 30,000 B.Zl, which is almost equal to the system's total cash surplus. Thus, under the unconstrained analysis, the Opole project could in effect be financed from within the system.

In summary, given the present combination of circumstances (a low-growth scenario, present surplus capacity, and an extremely favorable debt-to-equity ratio of about 3.0 percent) and assuming no constraints in the instant revaluation of assets, a real increase in revenues of 63 percent above current levels would be required to finance the generation system if no additional long-term debt were assumed.

### 5.4.2 Results by Generating Company

#### Coal Plants

The table in Exhibit 5-2 is a summary of the results for each individual plant. Using the results for the individual plants, the financial forecasts for each of the five generating companies (four companies with coal-fired plants and one company with all of the lignite plants) were consolidated. The assumed composition of each generating group is as follows:

| | |
|---|---|
| Group 1 | Jaworzno 3, Laziska, Siersza |
| Group 2 | Rybnick, Dolna Odra, Blacjownia, Halemba |
| Group 3 | Kozienice, Ostroleka, Stalowa Wola |
| Group 4 | Polaniec, Lagisza, Skawina |

The most relevant characteristics of each of these groups are compared in Exhibit 5-3. This exhibit shows that the range of revenue requirements is from 498 Zl/kWh for Group 2 to 574 Zl/kWh for Group 1 (that is, a variance of approximately 7 percent about the mean requirements of all coal-fired grid plants).

The results for the generating companies are presented in Exhibits 5-4 to 5-7 and include the income statement, balance sheet, and financial and operating ratios for each of them.

The Rybnik powerplant is the primary reason for the low revenue requirements of Group 2, and the Jaworzno 3 powerplant is the primary reason for the high revenue requirements of Group 1. If the objective is to make revenue requirements as uniform as possible, then one option would be to move Jaworzno 3 to Group 2 in exchange for Dolna Odra.

## Exhibit 5-2
## SUMMARY OF RESULTS FOR INDIVIDIAL PLANTS

| | | | | ENERGY | | | CAPACITY | | | REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|
| PLANT'S NAME | TYPE | AGE IN 1992 | CAPACITY (MW) | SALES (Gwh/Year) | COST (Zl/Kwh) | PRICE (Zl/Kwh) | SALES Mw-m | COST K Zl/Mw-m | PRICE K Zl/Mw-m | REQUIREMENTS (Zl/Kwh) |
| Adamow | Lignite | 28 | 480 | 2,472 | 250.711 | 253 000 | 5,355 | 62,605 | 65,000 | 383 277 |
| Belchatow | Lignite | 6 | 4,320 | 25,902 | 262.403 | 275 000 | 43,217 | 57,568 | 127,000 | 486 893 |
| Blachownia | Coal | 30 | 164 | 377 | 463.707 | 469 000 | 1,082 | 94,127 | 106,000 | 746 755 |
| Dolma | Coal | 6 | 1,600 | 5,583 | 291.108 | 327 000 | 14,971 | 67,445 | 94,000 | 579 067 |
| Halemba | Coal | 29 | 200 | 462 | 400.718 | 405 000 | 1,322 | 90,189 | 104,000 | 675 701 |
| Jaworzno 3 | Coal | 13 | 893 | 3,799 | 323.830 | 339 000 | 7,519 | 133,967 | 185,000 | 675 441 |
| Kozniecl | Coal | 18 | 2,600 | 8,000 | 298 181 | 299 000 | 24,237 | 71,238 | 98,000 | 595 888 |
| Lagisza | Coal | 23 | 721 | 2,144 | 375.485 | 384 000 | 4,541 | 60,518 | 87,000 | 552 945 |
| Laziska | Coal | 23 | 920 | 5,473 | 337.396 | 341 000 | 10,608 | 74,607 | 85,000 | 505 743 |
| Opole | Coal | | 360 | 2,289 | 340.583 | 628 000 | | | | 628 000 |
| Ostroleka B | Coal | 18 | 600 | 1,967 | 361.754 | 368 000 | 3,651 | 118,999 | 73,000 | 503 483 |
| Patnow | Lignite | 28 | 1,200 | 8,897 | 238.456 | 243 000 | 12,240 | 30,607 | 49,000 | 310 415 |
| Polaniec | Coal | 8 | 1,600 | 7,888 | 296.387 | 310 000 | 16,320 | 59,354 | 114,000 | 545 865 |
| Rybnik | Coal | 13 | 1,600 | 10,058 | 299.998 | 307 000 | 16,320 | 32,242 | 79,000 | 435 182 |
| Siersza | Coal | 23 | 630 | 1,712 | 374.195 | 382 000 | 3,765 | 67,925 | 92,000 | 567 080 |
| Skawina | Coal | 33 | 141 | 450 | 422.210 | 430 000 | 1,389 | 135,464 | | 807 743 |
| Stalowa | Coal | 23 | 311 | 1,951 | 280.761 | 282 000 | 3,172 | 97,759 | 0 | 282 000 |
| Turow | Lignite | 23 | 1,600 | 10,050 | 290.655 | 295.000 | 16,146 | 70,665 | 80,000 | 423 531 |
| TOTAL/AVERAGE | | 345 | 19,940 | 99,476 | 290.896 | 306.879 | 185,855 | | | 489.433 |

Notes:

1/ Based on 6.0% return on partially revalued net assets employed in 1994 (at Mid-1992 Prices)

2/ Prices are at June, 1992 levels, Exchange Rate is US$1.00 = Zl 13,400.

3/ Energy Cost includes Fuel at 1992 "ECONOMIC" Coal Price; Transport included in Coal Price; Environmental Penalty Coal Price is 29.970 Zl/Kj; Lignite price is 22 277 Zl/Kj

4/ Capacity Cost includes Operation & Maintenance; Depreciation; Plus (Minus) Interest Expense (Income).

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# EXHIBIT 5-3
## COMPARATIVE RESULTS FOR GENERATING COMPANIES

| | GROUP 1 | | GROUP 2 | | GROUP 3 | | GROUP 4 | |
|---|---|---|---|---|---|---|---|---|
| No of Plants | 3 | | 4 | | 3 | | 3 | |
| Energy Sales in 1994(Gwh) | 10,985 | | 16,480 | | 11,919 | | 10,482 | |
| Average Tariff ZE/Kwh | 574 | | 498 | | 529 | | 559 | |
| Total Revenue Billions ZE | 6,305 | | 8,204 | | 7,102 | | 5,935 | |
| Operating Income | 637 | | 892 | | 678 | | 873 | |
| Gross Fixed Assets | 31,020 | | 38,626 | | 34,276 | | 30,668 | |
| Accumulated Depreciation | 21,994 | 70 9% | 25,561 | 66 2% | 26,372 | 76 9% | 18,102 | 59 0% |
| Net Fixed Assets | 9,027 | | 13,065 | | 7,904 | | 12,566 | |
| Shareholders Equity | 12,902 | | 20,150 | | 14,740 | | 17,143 | |

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# INCOME STATEMENT – GROUP 1

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | 12,564 | Energy Sales -- Gwh | 10,570 | 10,754 | 10,985 | 10,788 | 9,980 | 9,115 |
| | | 2,563 | Capacity -- MW | 2,563 | 2,563 | 2,563 | 2,563 | 2,563 | 2,563 |
| | | | % Capacity Sold | | | | | | |
| | | 20,815 | Hours of Production/Year | 20,814 | 20,814 | 20,814 | 20,814 | 20,814 | 20,814 |
| | | 24,586 | Capacity Sales - Mw/m | 20,331 | 20,426 | 20,963 | 21,142 | 19,727 | 17,876 |
| | | | Max Capacity Sales @1994 Installation | 26,141 | 26,141 | 26,141 | 26,141 | 26,141 | 26,141 |
| | | 109.203 | Energy Sales Price -- Zl/Kwh | 242.702 | 346.445 | 346.700 | 346.693 | 346.508 | 346.549 |
| | | 65,719 | Capacity Price -- '000 Zl/Mw/m | 69,366 | 130,303 | 119,112 | 109,823 | 110,766 | 116,764 |
| | | | Adjusted 1994 Capacity Price | | | | | | |
| | | | Sales Revenue | | | | | | |
| | | 1,372 | Energy | 2,565 | 3,726 | 3,809 | 3,740 | 3,458 | 3,159 |
| | | 1,616 | Capacity | 1,410 | 2,662 | 2,497 | 2,322 | 2,185 | 2,087 |
| 180 | 1,537 | 3,007 | Sub-total Electricity Sales | 3,976 | 6,387 | 6,305 | 6,062 | 5,643 | 5,246 |
| 3 | 162 | 136 | Others | | | | | | |
| 183 | 1,698 | 3,142 | **Total Sales/Revenues** | 3,976 | 6,387 | 6,305 | 6,062 | 5,643 | 5,246 |
| | | | **Variable Cost** | | | | | | |
| 113 | 978 | 1,453 | Fuel | 1,532 | 3,215 | 3,284 | 3,222 | 2,969 | 2,703 |
| | | | Transport | 77 | | | | | |
| | | | Environmental Penalty | 416 | 423 | 433 | 427 | 398 | 367 |
| 3 | 22 | (1) | Others | | | | | | |
| 116 | 1,000 | 1,452 | Total Variable Cost @ 1992 Prices | 2,024 | 3,638 | 3,718 | 3,649 | 3,367 | 3,070 |
| | | | Plus: Inflation | | | | | | |
| 115 | 983 | 1,452 | **Total Variable Cost** | 2,024 | 3,638 | 3,718 | 3,649 | 3,367 | 3,070 |
| | | | **Fixed/ Capacity Costs** | | | | | | |
| 48 | 353 | 1,132 | Existing Plant | 1,232 | 1,108 | 985 | 869 | 793 | 749 |
| | | | New Plant | | | | | | |
| 48 | 353 | 1,132 | Total Fixed Cost (ex Dep'n)@1992 | 1,232 | 1,108 | 985 | 869 | 793 | 749 |
| | | | Plus: Inflation | | | | | | |
| 48 | 353 | 1,132 | **Total Fixed Cost before Dep'n.** | 1,232 | 1,108 | 985 | 869 | 793 | 749 |
| 4 | 76 | 252 | Depreciation Expense | 966 | 966 | 966 | 966 | 966 | 966 |
| 167 | 1,413 | 2,836 | Total Operating Expense | 4,222 | 5,712 | 5,669 | 5,483 | 5,126 | 4,785 |
| 16 | 286 | 307 | Operating Income | (246) | 675 | 637 | 579 | 517 | 461 |
| 4 | 31 | | Financial/Interest Expense (Net) | | | | | | |
| 1 | 29 | 31 | Extraordinary Income (Loss) | | | | | | |
| 13 | 283 | 337 | Income Before Tax | (246) | 675 | 637 | 579 | 517 | 461 |
| 3 | 136 | 215 | Corporate Tax | (98) | 270 | 255 | 231 | 207 | 184 |
| 10 | 147 | 123 | Net Income After Tax | (148) | 405 | 382 | 347 | 310 | 277 |

Billions Zloty at Base Year Prices

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## Exhibit 5-4b
## BALANCE SHEET - GROUP 1

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End - - December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **ASSETS** | | | | | | |
| | 113 | 255 | Cash | 238 | 345 | 341 | 327 | 301 | 274 |
| | 62 | 65 | Accounts Receivable | 87 | 149 | 148 | 143 | 136 | 129 |
| | 155 | 313 | Inventories - - Fuel | 298 | 605 | 617 | 603 | 547 | 492 |
| | | | Others | | | | | | |
| | 100 | (140) | Others | | | | | | |
| | 431 | 493 | Total Current Assets | 623 | 1,100 | 1,106 | 1,073 | 984 | 895 |
| | 5,214 | 5,622 | Gross Fixed Assets | 31,020 | 31,020 | 31,020 | 31,020 | 31,020 | 31,020 |
| | 3,078 | 3,421 | Less: Acc. Depreciation | 20,061 | 21,028 | 21,994 | 22,960 | 23,926 | 24,892 |
| | 2,137 | 2,201 | Net Fixed Assets | 10,959 | 9,993 | 9,027 | 8,061 | 7,095 | 6,129 |
| | 45 | 193 | Capital Work - in - Progress | 193 | 193 | 193 | 193 | 193 | 193 |
| | 2,612 | 2,886 | TOTAL ASSETS EMPLOYED | 11,775 | 11,285 | 10,326 | 9,327 | 8,271 | 7,216 |
| | | | **LIABILITIES** | | | | | | |
| | 116 | 214 | Accounts Payable | | | | | | |
| | 191 | 134 | Other Liabilities | | | | | | |
| | | | LTD due within 1 year - existing | | | | | | |
| | | | LTD due within 1 year - new local | | | | | | |
| | | | LTD due within 1 year - new FX | | | | | | |
| | | | Cash Deficiency (Surplus) | (340) | (1,235) | (2,576) | (3,922) | (5,288) | (6,620) |
| | 307 | 348 | Total Current Liabilities | (340) | (1,235) | (2,576) | (3,922) | (5,288) | (6,620) |
| | | | Other Liabilities | | | | | | |
| | | | Long Term Debt - existing | | | | | | |
| | | | Long Term Debt - new local | | | | | | |
| | | | Long Term Debt - new FX | | | | | | |
| | | | Total Long Term Debt | | | | | | |
| | | | Equity Balance: | | | | | | |
| | 2,215 | 2,329 | Assumed Opening Position | 2,329 | 2,329 | 2,329 | 2,329 | 2,329 | 2,329 |
| | | | Additional Paid in Capital | | | | | | |
| | | | Revaluation of Fixed Assets | 9,724 | 9,724 | 9,724 | 9,724 | 9,724 | 9,724 |
| | | 91 | Retained Earnings - - Prior Years | 209 | 62 | 466 | 848 | 1,196 | 1,506 |
| | 91 | 118 | Current Year's Net Income | (148) | 405 | 382 | 347 | 310 | 277 |
| | 2,306 | 2,538 | Total Equity | 12,115 | 12,520 | 12,902 | 13,249 | 13,560 | 13,836 |
| | 2,612 | 2,886 | TOTAL LIABILITIES & EQUITY | 11,775 | 11,285 | 10,326 | 9,327 | 8,271 | 7,216 |

Billions Zloty at Base Year Prices

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## Exhibit 5–4c
## OPERATING AND FINANCIAL RATIOS FOR GROUP 1

| PRO–FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End – – December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES** | | | | | | |
| | | | Energy Sales(Gwh) - Annual Growth - % | –15.9% | 1.7% | 2.2% | –1.8% | 7.5% | 8.7% |
| | 755.1% | 95.6% | Sales Revenue(Zl) - Annual Growth - % | 32.2% | 60.7% | –1.3% | –3.9% | 6.9% | 7.0% |
| | | 239.316 | Average Tariff - Zlotys/kwh | 376.122 | 593.942 | 573.998 | 561.933 | 565.461 | 575.542 |
| | | | **OPERATING RATIOS** | | | | | | |
| | | 115.551 | Variable Cost / kwh | 191.502 | 338.318 | 338.441 | 338.224 | 337.376 | 336.822 |
| | | 225.692 | Total Operating Cost/ kwh | 399.405 | 531.187 | 516.052 | 508.288 | 513.608 | 524.965 |
| | | 225.692 | Total Cost/ kwh (excl ROE) | 399.405 | 531.187 | 516.052 | 508.288 | 513.608 | 524.965 |
| | | 46,028 | Fixed Cost/ Mw/m | 60,573 | 54,245 | 46,989 | 41,078 | 40,183 | 41,889 |
| | | 56,284 | Fixed Cost plus Dep'n/ Mw/m | 108,090 | 101,543 | 93,075 | 86,772 | 89,154 | 95,934 |
| | | 56,284 | Fixed Cost plus Dep'n & Int /Mw/m | 108,090 | 101,543 | 93,075 | 86,772 | 89,154 | 95,934 |
| | 16.8% | 9.8% | Operating Income to Sales – % | –6.2% | 10.6% | 10.1% | 9.5% | 9.2% | 8.8% |
| | | | Operating Income to Gross Assets in Service (Average) – %: | | | | | | |
| | | 14.9% | – historical | | | | | | |
| | 11.0% | 5.7% | – revalued | –1.3% | 2.2% | 2.1% | 1.9% | 1.7% | 1.5% |
| | 22.3% | 11.7% | Operating Income/ Net Assets – % | –3.4% | 6.0% | 6.0% | 6.0% | 6.0% | 6.1% |
| | | | **BALANCE SHEET RATIOS** | | | | | | |
| | | 1.4 | Current Ratio | –1.8 | –0.9 | –0.4 | –0.3 | 0.2 | 0.1 |
| | | 1.0 | Cash at Bank to Sales – months | 0.7 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| | | 8 | Accts Receivable to Sales – days | 8 | 9 | 9 | 9 | 9 | 9 |
| | | | Debt to Equity Ratio – % | | | | | | |
| | | | – historical | | | | | | |
| | | 0.0% | – revalued | | | | | | |

Billions Zloty at Base Year Prices
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Exhibit 3-5a

# INCOME STATEMENT - GROUP 2

| PRO - FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | 16,393 | Energy Sales -- Gwh | 16,244 | 16,134 | 16,480 | 16,698 | 17,057 | 16,907 |
| | | 3,644 | Capacity -- MW | 3,644 | 3,605 | 3,564 | 3,564 | 3,523 | 3,441 |
| | | | % Capacity Sold | | | | | | |
| | | 11,917 | Hours of Production/Year | 11,917 | 11,917 | 11,917 | 11,917 | 11,917 | 11,917 |
| | | 36,584 | Capacity Sales - Mw/m | 32,848 | 32,551 | 33,481 | 34,065 | 34,446 | 33,938 |
| | | | Max Capacity Sales @1994 Installation | 37,169 | 36,771 | 36,353 | 36,353 | 35,935 | 35,098 |
| | | 124,576 | Energy Sales Price -- Zl/Kwh | 235.516 | 320 443 | 320 226 | 320 236 | 319.364 | 317 723 |
| | | 42,526 | Capacity Price -- '000 Zl/Mw/m | 52,498 | 94,804 | 87,401 | 80,844 | 75,318 | 72,952 |
| | | | Adjusted 1994 Capacity Price | | | | | | |
| | | | Sales Revenue | | | | | | |
| | | 2,042 | Energy | 3,826 | 5,170 | 5,277 | 5,347 | 5,447 | 5,372 |
| | | 1,556 | Capacity | 1,724 | 3,086 | 2,926 | 2,754 | 2,594 | 2,476 |
| 29 | 324 | 3,598 | Sub-total Electricity Sales | 5,550 | 8,256 | 8,204 | 8,101 | 8,042 | 7,848 |
| 7 | 78 | (1,049) | Others | | | | | | |
| 36 | 402 | 2,549 | Total Sales/Revenues | 5,550 | 8,256 | 8,204 | 8,101 | 8,042 | 7,848 |
| | | | Variable Cost | | | | | | |
| 16 | 113 | 1,082 | Fuel | 2,026 | 4,497 | 4,583 | 4,640 | 4,715 | 4,642 |
| | | | Transport | 564 | | | | | |
| | | 97 | Environmental Penalty | 413 | 411 | 419 | 424 | 432 | 429 |
| | | | Others | | | | | | |
| 16 | 113 | 1,179 | Total Variable Cost @ 1992 Prices | 3,003 | 4,908 | 5,003 | 5,064 | 5,147 | 5,071 |
| | | | Plus: Inflation | | | | | | |
| 16 | 113 | 1,179 | Total Variable Cost | 3,003 | 4,908 | 5,003 | 5,064 | 5,147 | 5,071 |
| | | | Fixed/ Capacity Costs | | | | | | |
| 16 | 149 | 964 | Existing Plant | 760 | 684 | 613 | 547 | 485 | 472 |
| | | | New Plant | | | | | | |
| 16 | 149 | 964 | Total Fixed Cost (ex.Dep'n)@1992 | 760 | 684 | 613 | 547 | 485 | 472 |
| | | | Plus: Inflation | | | | | | |
| 16 | 149 | 964 | Total Fixed Cost before Dep'n. | 760 | 684 | 613 | 547 | 485 | 472 |
| 1 | 7 | 211 | Depreciation Expense | 1,696 | 1,696 | 1,696 | 1,696 | 1,696 | 1,696 |
| 33 | 269 | 2,354 | Total Operating Expense | 5,459 | 7,288 | 7,311 | 7,307 | 7,328 | 7,239 |
| 3 | 133 | 195 | Operating Income | 92 | 968 | 892 | 794 | 714 | 609 |
| | | 48 | Financial/Interest Expense (Net) | (118) | (295) | (493) | (698) | (907) | (1,127) |
| (2) | (99) | 35 | Extraordinary Income (Loss) | | | | | | |
| 2 | 34 | 182 | Income Before Tax | 210 | 1,262 | 1,385 | 1,492 | 1,621 | 1 736 |
| | 18 | 137 | Corporate Tax | 84 | 505 | 554 | 597 | 648 | 694 |
| 1 | 16 | 45 | Net Income After Tax | 126 | 757 | 831 | 895 | 973 | 1 041 |

Billions Zloty at Base Year Prices

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## Exhibit 5-5b
## BALANCE SHEET – GROUP 2

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **ASSETS** | | | | | | |
| | 54 | 51 | Cash | 107 | 143 | 143 | 138 | 132 | 126 |
| | 38 | 216 | Accounts Receivable | 202 | 322 | 323 | 320 | 321 | 310 |
| | 119 | 226 | Inventories -- Fuel | 216 | 364 | 381 | 393 | 407 | 390 |
| | | | Others | | | | | | |
| | 50 | 35 | Others | | | | | | |
| | 261 | 528 | Total Current Assets | 526 | 830 | 847 | 851 | 860 | 825 |
| | 4,310 | 4,389 | Gross Fixed Assets | 38,626 | 38,626 | 38,626 | 38,626 | 38,626 | 38,626 |
| | 2,633 | 2,840 | Less Acc Depreciation | 22,170 | 23,865 | 25,561 | 27,257 | 28,953 | 30,649 |
| | 1,677 | 1,549 | Net Fixed Assets | 16,457 | 14,761 | 13,065 | 11,369 | 9,673 | 7,977 |
| | 70 | 160 | Capital Work-in Progress | 160 | 160 | 160 | 160 | 160 | 160 |
| | 2,008 | 2,237 | TOTAL ASSETS EMPLOYED | 17,142 | 15,750 | 14,072 | 12,380 | 10,694 | 8,963 |
| | | | **LIABILITIES** | | | | | | |
| | 87 | 115 | Accounts Payable | | | | | | |
| | 109 | 224 | Other Liabilities | | | | | | |
| | | | LTD due within 1 year - existing | | | | | | |
| | | | LTD due within 1 year - new local | | | | | | |
| | | | LTD due within 1 year - new FX | | | | | | |
| | | | Cash Deficiency (Surplus) | (1,418) | (3,568) | (6,077) | (8,665) | (11,324) | (14,096) |
| | 196 | 339 | Total Current Liabilities | (1,418) | (3,568) | (6,077) | (8,665) | (11,324) | (14,096) |
| | | | Other Liabilities | | | | | | |
| | 11 | 67 | Long Term Debt - existing | | | | | | |
| | | | Long Term Debt - new local | | | | | | |
| | | | Long Term Debt - new FX | | | | | | |
| | | | Total Long Term Debt | | | | | | |
| | | | **Equity Balance:** | | | | | | |
| | 325 | 328 | Assumed Opening Position | 328 | 328 | 328 | 328 | 328 | 328 |
| | | | Additional Paid in Capital | | | | | | |
| | 77 | | Revaluation of Fixed Assets | 16,603 | 16,603 | 16,603 | 16,603 | 16,603 | 16,603 |
| | 1,384 | 1,459 | Retained Earnings -- Prior Years | 1,504 | 1,630 | 2,387 | 3,218 | 4,114 | 5,086 |
| | 16 | 45 | Current Year's Net Income | 126 | 757 | 831 | 895 | 973 | 1,041 |
| | 1,801 | 1,832 | Total Equity | 18,561 | 19,318 | 20,150 | 21,045 | 22,018 | 23,059 |
| | 2,008 | 2,237 | TOTAL LIABILITIES & EQUITY | 17,142 | 15,750 | 14,072 | 12,380 | 10,694 | 8,963 |

Billions Zloty at Base Year Prices
Case gencobas\system v\group2

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## Exhibit 5-5c
## OPERATING AND FINANCIAL RATIOS FOR GROUP 2

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES** | | | | | | |
| | | | Energy Sales(Gwh) - Annual Growth - % | -0.9% | -0.7% | 2.1% | 1.3% | 2.2% | -0.9% |
| | 1010.7% | 1008.9% | Sales Revenue(Zl) - Annual Growth - % | 54.3% | 48.7% | -0.6% | -1.2% | -0.7% | -2.4% |
| | | 219.481 | Average Tariff - - Zlotys/kwh | 341.674 | 511.720 | 497.793 | 485.168 | 471.469 | 464.159 |
| | | | **OPERATING RATIOS** | | | | | | |
| | | 71.697 | Variable Cost / kwh | 184.856 | 304.230 | 303.553 | 303.289 | 301.775 | 299.944 |
| | | 143.584 | Total Operating Cost/ kwh | 336.033 | 451.727 | 443.651 | 437.593 | 429.608 | 428.151 |
| | | 146.536 | Total Cost/ kwh (excl ROE) | 328.751 | 433.470 | 413.729 | 395.792 | 376.427 | 361.510 |
| | | 26.344 | Fixed Cost/ Mw/m | 23.134 | 21.007 | 18.308 | 16.049 | 14.067 | 13.902 |
| | | 32.122 | Fixed Cost plus Dep'n/ Mw/m | 74.761 | 73.105 | 68.959 | 65.831 | 63.299 | 63.871 |
| | | 33.445 | Fixed Cost plus Dep'n & Int /Mw/m | 71.160 | 64.056 | 54.231 | 45.341 | 36.965 | 30.671 |
| | 33.0% | 7.7% | Operating Income to Sales - % | 1.7% | 11.7% | 10.9% | 9.8% | 8.9% | 7.8% |
| | | | Operating Income to Gross Assets in Service (Average) - % | | | | | | |
| | | 14.9% | -historical | | | | | | |
| | 6.2% | 4.5% | -revalued | 0.4% | 2.5% | 2.3% | 2.1% | 1.8% | 1.6% |
| | 13.7% | 9.7% | Operating Income/ Net Assets - % | 1.0% | 5.9% | 6.0% | 6.1% | 6.3% | 6.3% |
| | | | **BALANCE SHEET RATIOS** | | | | | | |
| | | 1.6 | Current Ratio | -0.4 | -0.2 | -0.1 | -0.1 | -0.1 | 0.1 |
| | | 0.2 | Cash at Bank to Sales - months | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| | | 31 | Accts Receivable to Sales - days | 13 | 14 | 14 | 14 | 15 | 14 |
| | | | Debt to Equity Ratio - % | | | | | | |
| | | | -historical | | | | | | |
| | | | -revalued | | | | | | |

Billions Zloty at Base Year Prices
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## INCOME S...TEMENT – GROUP 3

| PRO - FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End – – December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | 11,226 | Energy Sales Gwh | 11,426 | 11,484 | 11,919 | 12,102 | 12,228 | 11,902 |
| | | 3,545 | Capacity – – MW | 3,545 | 3,545 | 3,511 | 3,511 | 3,511 | 3,511 |
| | | | % Capacity Sold | | | | | | |
| | | | Hours of Production/Year | | | | | | |
| | | 30,300 | Capacity Sales - Mw/m | 29,509 | 29,628 | 31,060 | 31,613 | 32,091 | 31,241 |
| | | | Max Capacity Sales @1994 Installation | 36,159 | 36,159 | 35,812 | 35,812 | 35,812 | 35,812 |
| | | 132 304 | Energy Sales Price – – Zl/Kwh | 230.474 | 306 729 | 307.605 | 307.490 | 306 942 | 306 472 |
| | | 42,614 | Capacity Price – – '000 Zl/Mw/m | 54,596 | 91,983 | 85,052 | 80,224 | 76,052 | 71,877 |
| | | | Adjusted 1994 Capacity Price | | | | | | |
| | | | Sales Revenue | | | | | | |
| | | 1,485 | Energy | 2,633 | 3,522 | 3,666 | 3,721 | 3,753 | 3,648 |
| | | 1,291 | Capacity | 1,611 | 2,725 | 2,642 | 2,536 | 2,441 | 2,246 |
| | | 2,776 | Sub - total Electricity Sales | 4,244 | 6,248 | 6,308 | 6,257 | 6,194 | 5,893 |
| | | 909 | Others | 912 | 795 | 795 | 795 | 795 | 795 |
| | | 3,686 | **Total Sales/Revenues** | 5,156 | 7,042 | 7,102 | 7,052 | 6,989 | 6,688 |
| | | | Variable Cost | | | | | | |
| | | 1,598 | Fuel | 1,285 | 3,239 | 3,371 | 3,422 | 3,451 | 3,354 |
| | | | Transport | 606 | | | | | |
| | | 119 | Environmental Penalty | 262 | 263 | 274 | 278 | 281 | 273 |
| | | | Others | | | | | | |
| | | 1,717 | Total Variable Cost @ 1992 Prices | 2,153 | 3,502 | 3,645 | 3,700 | 3,732 | 3,627 |
| | | | Plus: Inflation | | | | | | |
| | | 1,717 | **Total Variable Cost** | 2,153 | 3,502 | 3,645 | 3,700 | 3,732 | 3,627 |
| | | | Fixed/ Capacity Costs | | | | | | |
| | | 1,141 | Existing Plant | 1,039 | 998 | 982 | 967 | 967 | 967 |
| | | | New Plant | | | | | | |
| | | 1,141 | Total Fixed Cost (ex.Dep'n)@1992 | 1,039 | 998 | 982 | 967 | 967 | 967 |
| | | | Plus: Inflation | | | | | | |
| | | 1,141 | **Total Fixed Cost before Dep'n.** | 1,039 | 998 | 982 | 967 | 967 | 967 |
| | | 377 | Depreciation Expense | 1,797 | 1,797 | 1,797 | 1,797 | 1,797 | 1,848 |
| | | 3,235 | Total Operating Expense | 4,989 | 6,297 | 6,424 | 6,464 | 6,497 | 6,442 |
| | | 450 | Operating Income | 167 | 745 | 678 | 588 | 492 | 246 |
| | | 147 | Financial/Interest Expense (Net) | (81) | (167) | (253) | (327) | (437) | (598) |
| | | 45 | Extraordinary Income (Loss) | | | | | | |
| | | 348 | Income Before Tax | 248 | 912 | 931 | 915 | 929 | 843 |
| | | 152 | Corporate Tax | 99 | 365 | 372 | 366 | 372 | 337 |
| | | 196 | Net Income After Tax | 149 | 547 | 559 | 549 | 557 | 506 |

Billions Zloty at Base Year Prices
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## Exhibit 5-6b
## BALANCE SHEET - GROUP 3

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **ASSETS** | | | | | | |
| | 50 | 95 | Cash | 113 | 160 | 166 | 168 | 170 | 166 |
| | 97 | 467 | Accounts Receivable | 493 | 562 | 557 | 554 | 551 | 533 |
| | 172 | 360 | Inventories -- Fuel | 440 | 756 | 788 | 801 | 810 | 788 |
| | 3 | 2 | Others | | | | | | |
| | 66 | 48 | Others | | 450 | 850 | 1,300 | 1,700 | 2,000 |
| | 388 | 992 | **Total Current Assets** | 1,046 | 1,927 | 2,362 | 2,823 | 3,230 | 3,487 |
| | 2,325 | 2,409 | Gross Fixed Assets | 34,259 | 34,276 | 34,276 | 34,276 | 35,529 | 36,480 |
| | 1,404 | 1,502 | Less: Acc. Depreciation | 22,778 | 24,574 | 26,372 | 28,169 | 29,967 | 31,814 |
| | 920 | 907 | Net Fixed Assets | 11,481 | 9,701 | 7,904 | 6,106 | 5,562 | 4,666 |
| | 31 | 98 | Capital Work-in-Progress | 98 | 462 | 1,318 | 2,270 | 1,587 | 731 |
| | 1,339 | 1,996 | **TOTAL ASSETS EMPLOYED** | 12,625 | 12,090 | 11,583 | 11,199 | 10,380 | 8,884 |
| | | | **LIABILITIES** | | | | | | |
| | 104 | 270 | Accounts Payable | | | | | | |
| | (79) | 286 | Other Liabilities | | | | | | |
| | | | LTD due within 1 year - existing | | | | | | |
| | | | LTD due within 1 year - new local | | | | | | |
| | | | LTD due within 1 year - new FX | | | | | | |
| | | | Cash Deficiency (Surplus) | (1,009) | (2,091) | (3,157) | (4,090) | (5,467) | (7,469) |
| | 25 | 556 | **Total Current Liabilities** | (1,009) | (2,091) | (3,157) | (4,090) | (5,467) | (7,469) |
| | | | Other Liabilities | | | | | | |
| | 270 | 326 | Long Term Debt - existing | | | | | | |
| | | | Long Term Debt - new local | | | | | | |
| | | | Long Term Debt - new FX | | | | | | |
| | | | **Total Long Term Debt** | | | | | | |
| | | | **Equity Balance:** | | | | | | |
| | | | Assumed Opening Position | | | | | | |
| | | | Additional Paid in Capital | | | | | | |
| | 17 | | Revaluation of Fixed Assets | 12,371 | 12,371 | 12,371 | 12,371 | 12,371 | 12,371 |
| | 947 | 1,035 | Retained Earnings -- Prior Years | 1,114 | 1,263 | 1,811 | 2,369 | 2,918 | 3,476 |
| | 80 | 80 | Current Year's Net Income | 149 | 547 | 559 | 549 | 557 | 506 |
| | 1,045 | 1,114 | **Total Equity** | 13,634 | 14,182 | 14,740 | 15,289 | 15,847 | 16,353 |
| | 1,339 | 1,996 | **TOTAL LIABILITIES & EQUITY** | 12,625 | 12,090 | 11,583 | 11,199 | 10,380 | 8,884 |

Billions Zloty at Base Year Prices
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## Exhibit 5-6c
## OPERATING AND FINANCIAL RATIOS FOR GROUP 3

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES** | | | | | | |
| | | | Energy Sales(Gwh) - Annual Growth % | 1.8% | 0.5% | 3.8% | 1.5% | 1.0% | 2.7% |
| | | | Sales Revenue(Zl) - Annual Growth % | 52.9% | 47.2% | 1.0% | -0.8% | 1.0% | 4.9% |
| | | 247 326 | Average Tariff - Zlotys/kwh | 371.479 | 544.045 | 529.251 | 517.047 | 506.524 | 495.140 |
| | | | **OPERATING RATIOS** | | | | | | |
| | | 152 929 | Variable Cost / kwh | 188.442 | 304.972 | 305.822 | 305.720 | 305.218 | 304.778 |
| | | 288 207 | Total Operating Cost/ kwh | 436.654 | 548.340 | 538.994 | 534.147 | 531.285 | 541.259 |
| | | 301 339 | Total Cost/ kwh (excl ROE) | 429.590 | 533.770 | 517.805 | 507.109 | 495.519 | 491.056 |
| | | 37.670 | Fixed Cost/ Mw/m | 35,219 | 33,685 | 31,606 | 30,590 | 30,134 | 30,954 |
| | | 50.117 | Fixed Cost plus Dep'n/ Mw/m | 96,106 | 94,328 | 89,476 | 87,448 | 86,144 | 90,092 |
| | | 54.983 | Fixed Cost plus Dep'n & Int /Mw/m | 93,371 | 88,681 | 81,344 | 77,097 | 72,515 | 70,967 |
| | | 12.2% | Operating Income to Sales - % | 3.2% | 10.6% | 9.6% | 8.3% | 7.0% | 3.7% |
| | | | Operating Income to Gross Assets in Service (Average) - % | | | | | | |
| | | 14.9% | -historical | | | | | | |
| | | 19.0% | -revalued | 0.9% | 2.2% | 2.0% | 1.7% | 1.4% | 0.7% |
| | | 28.1% | Operating Income/ Net Assets - % | 2.3% | 6.2% | 6.2% | 6.1% | 5.5% | 2.9% |
| | | | **BALANCE SHEET RATIOS** | | | | | | |
| | | 1.8 | Current Ratio | -1.0 | -0.9 | -0.7 | -0.7 | 0.6 | 0.5 |
| | | 0.3 | Cash at Bank to Sales - months | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| | | 46 | Accts.Receivable to Sales - days | 35 | 29 | 29 | 29 | 29 | 29 |
| | | | Debt to Equity Ratio - % | | | | | | |
| | | | -historical | | | | | | |
| | | | -revalued | | | | | | |

Billions Zloty at Base Year Prices
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## Exhibit 5-7a
## INCOME STATEMENT - GROUP 4

| PRO - FORMA | ACTUAL | ACTUAL | POLISH GENERATING COMPANIES | ESTIMATE | FORECAST | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1989 | 1990 | 1991 | Year End -- December 31 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 |
| | | 11,495 | Energy Sales -- Gwh | 10,008 | 10,994 | 10,482 | 9,466 | 8,368 | 7,497 |
| | | 2,901 | Capacity -- MW | 2,604 | 2,533 | 2,462 | 2,462 | 2,462 | 2,321 |
| | | | % Capacity Sold | | | | | | |
| | | 12,077 | Hours of Production/Year | 12,077 | 12,077 | 12,077 | 12,077 | 12,077 | 5,916 |
| | | 27,144 | Capacity Sales - Mw/m | 22,215 | 21,966 | 21,744 | 21,704 | 19,592 | 17,391 |
| | | | Max Capacity Sales @1994 Installation | 26,559 | 25,838 | 25,116 | 25,116 | 25,116 | 23,674 |
| | | 117,484 | Energy Sales Price -- Zl/Kwh | 223,040 | 330,164 | 330,291 | 332,351 | 333,577 | 326,318 |
| | | 47,872 | Capacity Price -- '000 Zl/Mw/m | 54,040 | 112,933 | 110,046 | 105,698 | 112,433 | 115,441 |
| | | | Adjusted 1994 Capacity Price | | | | | | |
| | | | Sales Revenue | | | | | | |
| | | 1,350 | Energy | 2,232 | 3,630 | 3,462 | 3,146 | 2,791 | 2,461 |
| | | 1,299 | Capacity | 1,201 | 2,481 | 2,393 | 2,294 | 2,203 | 2,008 |
| 73 | 699 | 2,650 | Sub - total Electricity Sales | 3,433 | 6,110 | 5,855 | 5,440 | 4,994 | 4,469 |
| 7 | 78 | 236 | Others | 100 | 90 | 80 | 80 | 80 | 60 |
| 81 | 777 | 2,885 | Total Sales/Revenues | 3,533 | 6,200 | 5,935 | 5,520 | 5,074 | 4,529 |
| | | | Variable Cost | | | | | | |
| 41 | 379 | 1,248 | Fuel | 1,206 | 3,196 | 3,045 | 2,764 | 2,451 | 2,162 |
| | | | Transport | 446 | | | | | |
| | | 89 | Environmental Penalty | 281 | 300 | 288 | 267 | 239 | 206 |
| | | | Others | | | | | | |
| 41 | 379 | 1,335 | Total Variable Cost @ 1992 Prices | 1,932 | 3,496 | 3,333 | 3,030 | 2,690 | 2,369 |
| | | | Plus: Inflation | | | | | | |
| 41 | 379 | 1,335 | Total Variable Cost | 1,932 | 3,496 | 3,333 | 3,030 | 2,690 | 2,369 |
| | | | Fixed/ Capacity Costs | | | | | | |
| 31 | 237 | 1,000 | Existing Plant | 892 | 788 | 721 | 675 | 647 | 575 |
| | | | New Plant | | | | | | |
| 31 | 237 | 1,000 | Total Fixed Cost (ex Dep'n)@1992 | 892 | 788 | 721 | 675 | 647 | 575 |
| | | | Plus: Inflation | | | | | | |
| 31 | 237 | 1,000 | Total Fixed Cost before Dep'n. | 892 | 788 | 721 | 675 | 647 | 575 |
| 2 | 32 | 349 | Depreciation Expense | 1,009 | 1,009 | 1,009 | 1,009 | 1,009 | 974 |
| 73 | 648 | 2,684 | Total Operating Expense | 3,833 | 5,292 | 5,062 | 4,714 | 4,346 | 3,918 |
| 8 | 129 | 201 | Operating Income | (300) | 908 | 873 | 807 | 728 | 612 |
| | | | Financial/Interest Expense (Net) | (51) | (136) | (265) | (403) | (543) | (679) |
| 1 | 1 | 45 | Extraordinary Income (Loss) | | | | | | |
| 7 | 126 | 233 | Income Before Tax | (249) | 1,044 | 1,138 | 1,209 | 1,271 | 1,291 |
| 1 | 60 | 174 | Corporate Tax | (100) | 418 | 455 | 484 | 508 | 516 |
| 5 | 66 | 60 | Net Income After Tax | (150) | 626 | 683 | 726 | 763 | 774 |

Billions Zloty at Base Year Prices

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## Exhibit 5-7b
## BALANCE SHEET - GROUP 4

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **ASSETS** | | | | | | |
| | 96 | 100 | Cash | 140 | 219 | 207 | 185 | 165 | 149 |
| | 48 | 171 | Accounts Receivable | 193 | 340 | 330 | 309 | 286 | 262 |
| | 141 | 366 | Inventories -- Fuel | 407 | 789 | 754 | 684 | 606 | 541 |
| | 1 | 6 | Others | | | | | | |
| | 8 | 1 | Others | | | | | | |
| | 294 | 645 | **Total Current Assets** | 739 | 1,349 | 1,291 | 1,179 | 1,057 | 952 |
| | 7,422 | 7,582 | Gross Fixed Assets | 30,668 | 30,668 | 30,668 | 30,668 | 30,668 | 30,668 |
| | 3,143 | 3,493 | Less Acc Depreciation | 16,085 | 17,094 | 18,102 | 19,111 | 20,120 | 21,094 |
| | 4,279 | 4,089 | Net Fixed Assets | 14,583 | 13,575 | 12,566 | 11,557 | 10,549 | 9,575 |
| | 78 | 137 | Capital Work - in Progress | 137 | 137 | 137 | 137 | 137 | 137 |
| | 4,651 | 4,871 | **TOTAL ASSETS EMPLOYED** | 15,460 | 15,060 | 13,994 | 12,873 | 11,743 | 10,664 |
| | | | **LIABILITIES** | | | | | | |
| | 50 | 238 | Accounts Payable | | | | | | |
| | 116 | 136 | Other Liabilities | | | | | | |
| | | | LTD due within 1 year - existing | | | | | | |
| | 10 | 18 | LTD due within 1 year - new local | | | | | | |
| | | | LTD due within 1 year - new FX | | | | | | |
| | | | Cash Deficiency (Surplus) | (374) | (1,400) | (3,149) | (4,995) | (6,888) | (8,742) |
| | 176 | 391 | **Total Current Liabilities** | (374) | (1,400) | (3,149) | (4,995) | (6,888) | (8,742) |
| | | | Other Liabilities | | | | | | |
| | 1 | | Long Term Debt - existing | | | | | | |
| | | | Long Term Debt - new local | | | | | | |
| | | | Long Term Debt - new FX | | | | | | |
| | | | **Total Long Term Debt** | | | | | | |
| | | | **Equity Balance:** | | | | | | |
| | 4,375 | 4,421 | Assumed Opening Position | 4,421 | 4,421 | 4,421 | 4,421 | 4,421 | 4,421 |
| | | | Additional Paid in Capital | | | | | | |
| | | | Revaluation of Fixed Assets | 11,503 | 11,503 | 11,503 | 11,503 | 11,503 | 11,503 |
| | | | Retained Earnings -- Prior Years | 59 | (91) | 536 | 1,219 | 1,944 | 2,707 |
| | 99 | 59 | Current Year's Net Income | (150) | 626 | 683 | 726 | 763 | 774 |
| | 4,474 | 4,480 | **Total Equity** | 15,834 | 16,460 | 17,143 | 17,868 | 18,631 | 19,405 |
| | 4,651 | 4,871 | **TOTAL LIABILITIES & EQUITY** | 15,460 | 15,060 | 13,994 | 12,873 | 11,743 | 10,664 |

Billions Zloty at Base Year Prices
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## Exhibit 5-7c
## OPERATING AND FINANCIAL RATIOS FOR GROUP 4

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES** | | | | | | |
| | | | Energy Sales(Gwh) - Annual Growth - % | -12.9% | 9.9% | -4.7% | -9.7% | -11.6% | -10.4% |
| | 851.6% | 279.0% | Sales Revenue(Zl) - Annual Growth - % | 29.5% | 78.0% | -4.2% | -7.1% | -8.2% | -10.5% |
| | | 230.533 | Average Tariff -- Zlotys/kwh | 342.993 | 555.797 | 558.560 | 574.697 | 596.820 | 596.109 |
| | | | **OPERATING RATIOS** | | | | | | |
| | | 116.165 | Variable Cost / kwh | 193.063 | 317.984 | 317.971 | 320.113 | 321.468 | 315.967 |
| | | 233.508 | Total Operating Cost/ kwh | 382.990 | 481.379 | 482.948 | 497.939 | 519.335 | 522.544 |
| | | 233.544 | Total Cost/ kwh (excl. ROE) | 377.893 | 469.021 | 457.644 | 455.407 | 454.501 | 431.935 |
| | | 36.840 | Fixed Cost/ Mw/m | 40.160 | 35.862 | 33.145 | 31.086 | 33.027 | 33.046 |
| | | 49.690 | Fixed Cost plus Dep'n/ Mw/m | 85.564 | 81.782 | 79.533 | 77.558 | 84.510 | 89.053 |
| | | 49.706 | Fixed Cost plus Dep'n & Int /Mw/m | 83.268 | 75.596 | 67.335 | 59.008 | 56.819 | 49.992 |
| | 16.6% | 7.0% | Operating Income to Sales - % | -8.5% | 14.6% | 14.7% | 14.6% | 14.4% | 13.5% |
| | | | Operating Income to Gross Assets in Service (Average) - % | | | | | | |
| | | 14.9% | -historical | | | | | | |
| | 3.5% | 2.7% | -revalued | -1.6% | 3.0% | 2.8% | 2.6% | 2.4% | 2.0% |
| | 5.7% | 4.3% | Operating Income/ Net Assets - % | -3.0% | 6.0% | 6.1% | 6.1% | 6.0% | 5.5% |
| | | | **BALANCE SHEET RATIOS** | | | | | | |
| | | 1.6 | Current Ratio | -2.0 | -1.0 | -0.4 | -0.2 | -0.2 | -0.1 |
| | | 0.4 | Cash at Bank to Sales - months | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| | | 22 | Accts Receivable to Sales - days | 20 | 20 | 20 | 20 | 21 | 21 |
| | | | Debt to Equity Ratio - % | | | | | | |
| | | | -historical | | | | | | |
| | | | -revalued | | | | | | |

Billions Zloty at Base Year Prices
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### Lignite Plants

The group of lignite plants has approximately the same amount of sales as all four generating companies with coal plants. It is projected that the revenue requirement for the lignite group will be 434 Zl/kWh in 1994, or about 19 percent lower than for coal plants. The financial statements for the lignite group are shown in Exhibit 5-8.

In contrast to the coal plants, a rate of return of 6 percent on net assets of the lignite group is not sufficient to cover all cash requirements. This is largely due to work planned in the Patnow and Turow plants.

Therefore, some debt increase is necessary. The total cash deficiency is projected to increase to 10,837 B.Zl by 1997, while long-term debt will increase from 3,772 B.Zl in 1992 to 9,945 B.Zl in 1997. Nevertheless, the total debt-to-equity ratio is projected to increase to a very reasonable 16.6 percent by 1997.

Exhibit 5-8a

# INCOME STATEMENT – LIGNITE GROUP

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | 46,170 | Energy Sales -- Gwh | 48,762 | 46,972 | 47,521 | 48,792 | 48,792 | 48,792 |
| | | 8,120 | Capacity -- MW | 8,120 | 8,120 | 7,720 | 7,570 | 6,690 | 7,320 |
| | | | % Capacity Sold | | | | | | |
| | | 28,327 | Hours of Production/Year | 28,818 | 28,818 | 29,957 | 31,096 | 21,983 | 21,983 |
| | | 76,698 | Capacity Sales - Mw/m | 80,900 | 77,810 | 76,958 | 75,602 | 66,626 | 73,052 |
| | | | Max Capacity Sales @1994 Installation | 82,824 | 82,824 | 78,744 | 77,214 | 68,238 | 74,664 |
| | | 109.409 | Energy Sales Price -- Zl/Kwh | 160.585 | 274.096 | 272.002 | 271.246 | 271.246 | 271.246 |
| | | 40,633 | Capacity Price -- '000 Zl/Mw/m | 50,253 | 100,776 | 100,071 | 104,888 | 119,120 | 124,731 |
| | | | Adjusted 1994 Capacity Price | | | | | | |
| | | | Sales Revenue | | | | | | |
| | | 5,051 | Energy | 7,830 | 12,875 | 12,926 | 13,235 | 13,235 | 13,235 |
| | | 3,116 | Capacity | 4,065 | 7,841 | 7,701 | 7,930 | 7,936 | 9,112 |
| | 1,137 | 8,168 | Sub-total Electricity Sales | 11,896 | 20,716 | 20,627 | 21,164 | 21,171 | 22,346 |
| | 3 | 181 | Others | | | | | | |
| | 1,141 | 8,349 | Total Sales/Revenues | 11,896 | 20,716 | 20,627 | 21,164 | 21,171 | 22,346 |
| | | | Variable Cost | | | | | | |
| | 618 | 5,358 | Fuel | 5,544 | 11,147 | 11,230 | 11,506 | 11,506 | 11,506 |
| | 88 | | Transport | 1 | | | | | |
| | 49 | 297 | Environmental Penalty | 1,347 | 1,290 | 1,279 | 1,306 | 1,306 | 1,306 |
| | 6 | 6 | Others | | | | | | |
| | 761 | 5,661 | Total Variable Cost @ 1992 Prices | 6,891 | 12,437 | 12,509 | 12,812 | 12,812 | 12,812 |
| | | | Plus: Inflation | | | | | | |
| | 761 | 5,661 | Total Variable Cost | 6,891 | 12,437 | 12,509 | 12,812 | 12,812 | 12,812 |
| | | | Fixed/ Capacity Costs | | | | | | |
| | 211 | 1,628 | Existing Plant | 2,475 | 2,201 | 2,042 | 1,899 | 1,804 | 1,739 |
| | | | New Plant | | | | | | |
| | | 1,093 | Total Fixed Cost (ex Dep'n)@1992 | 1,773 | 1,595 | 1,520 | 1,448 | 1,414 | 1,402 |
| | | | Plus: Inflation | | | | | | |
| | 211 | 1,628 | Total Fixed Cost before Dep'n. | 2,475 | 2,201 | 2,042 | 1,899 | 1,804 | 1,739 |
| | 25 | 757 | Depreciation Expense | 3,486 | 3,486 | 3,333 | 3,436 | 3,721 | 3,955 |
| | 143 | 5,921 | Total Operating Expense | 9,617 | 13,838 | 14,017 | 14,359 | 14,101 | 15,106 |
| | 143 | 303 | Operating Income | (956) | 2,592 | 2,742 | 3,017 | 2,834 | 3,841 |
| | | (131) | Financial/Interest Expense (Net) | (307) | (601) | (736) | (856) | (936) | (944) |
| | 2 | 265 | Extraordinary Income (Loss) | | | | | | |
| | 145 | 699 | Income Before Tax | (649) | 3,193 | 3,479 | 3,873 | 3,770 | 4,785 |
| | 65 | 302 | Corporate Tax | (260) | 1,277 | 1,391 | 1,549 | 1,508 | 1,914 |
| | 79 | 396 | Net Income After Tax | (390) | 1,916 | 2,087 | 2,324 | 2,262 | 2,871 |

Billions Zloty at Base Year Prices

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Exhibit 5-8b

BALANCE SHEET – LIGNITE GROUP

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **ASSETS** | | | | | | |
| | 231 | 223 | Cash | 281 | 421 | 427 | 431 | 430 | 430 |
| | 129 | 458 | Accounts Receivable | 637 | 1,107 | 1,124 | 1,165 | 1,184 | 1,227 |
| | 210 | 328 | Inventories -- Fuel | 333 | 657 | 671 | 689 | 689 | 689 |
| | 8 | 12 | Others | | | | | | |
| | 244 | 280 | Others | | | | | | |
| | 822 | 1,302 | Total Current Assets | 1,251 | 2,184 | 2,222 | 2,285 | 2,304 | 2,346 |
| | 15,855 | 16,832 | Gross Fixed Assets | 85,242 | 85,242 | 93,723 | 102,675 | 110,398 | 129,161 |
| | 6,176 | 7,039 | Less Acc Depreciation | 41,303 | 44,789 | 48,123 | 51,559 | 55,280 | 59,235 |
| | 9,678 | 9,793 | Net Fixed Assets | 43,938 | 40,452 | 45,600 | 51,116 | 55,118 | 69,927 |
| | 1,189 | 2,682 | Capital Work-in-Progress | 4,363 | 11,594 | 12,775 | 11,864 | 16,307 | 8,517 |
| | 11,689 | 13,777 | TOTAL ASSETS EMPLOYED | 49,552 | 54,230 | 60,597 | 65,265 | 73,728 | 80,790 |
| | | | **LIABILITIES** | | | | | | |
| | 245 | 493 | Accounts Payable | | | | | | |
| | 220 | 141 | Other Liabilities | | | | | | |
| | | | LTD due within 1 year - existing | 170 | 170 | 170 | 170 | 170 | 170 |
| | | | LTD due within 1 year - new local | | | | | | |
| | | | LTD due within 1 year - new FX | | | | | | |
| | | | Cash Deficiency (Surplus) | (2,769) | (1,103) | 1,974 | 3,718 | 7,268 | 10,837 |
| | 465 | 634 | Total Current Liabilities | (2,599) | (933) | 2,144 | 3,888 | 7,437 | 11,006 |
| | (50) | | Other Liabilities | 704 | 1,970 | 3,342 | 4,112 | 6,934 | 7,725 |
| | 1,166 | 2,100 | Long Term Debt - existing | 3,068 | 2,899 | 2,729 | 2,559 | 2,390 | 2,220 |
| | | 162 | Long Term Debt - new local | 704 | 1,970 | 3,342 | 4,112 | 6,934 | 7,725 |
| | | | Long Term Debt - new FX | | | | | | |
| | | | Total Long Term Debt | 3,772 | 4,869 | 6,071 | 6,671 | 9,323 | 9,945 |
| | | | **Equity Balance:** | | | | | | |
| | 7,743 | 8,563 | Assumed Opening Position | 10,227 | 10,227 | 10,227 | 10,227 | 10,227 | 10,227 |
| | 1,199 | 1,286 | Additional Paid in Capital | | | | | | |
| | 388 | 378 | Revaluation of Fixed Assets | 37,631 | 37,631 | 37,631 | 37,631 | 37,631 | 37,631 |
| | 502 | 519 | Retained Earnings -- Prior Years | 911 | 522 | 2,437 | 4,524 | 6,848 | 9,110 |
| | 220 | 393 | Current Year's Net Income | (390) | 1,916 | 2,087 | 2,324 | 2,262 | 2,871 |
| | 10,052 | 11,136 | Total Equity | 48,379 | 50,295 | 52,382 | 54,706 | 56,968 | 59,839 |
| | 11,689 | 13,777 | TOTAL LIABILITIES & EQUITY | 49,552 | 54,230 | 60,597 | 65,265 | 73,728 | 80,790 |

Billions Zloty at Base Year Prices

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## Exhibit 5-8c
## OPERATING AND FINANCIAL RATIOS FOR LIGNITE GROUP

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | 1993 | FORECAST 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES** | | | | | | |
| | | | Energy Sales(Gwh) - Annual Growth - % | 5.6% | -3.7% | 1.2% | 2.7% | 0.0% | 0.0% |
| | | 618.1% | Sales Revenue(Zl) - Annual Growth - % | 45.6% | 74.1% | -0.4% | 2.6% | 0.0% | 5.6% |
| | | 176.909 | Average Tariff -- Zlotys/kwh | 243.958 | 441.035 | 434.064 | 433.769 | 433.907 | 457.997 |
| | | | **OPERATING RATIOS** | | | | | | |
| | | 122.610 | Variable Cost / kwh | 141.326 | 264.784 | 263.237 | 262.592 | 262.592 | 262.592 |
| | | 128.253 | Total Operating Cost/ kwh | 197.227 | 294.594 | 294.965 | 294.288 | 289.007 | 309.598 |
| | | 125.416 | Total Cost/ kwh (excl. ROE) | 190.926 | 281.799 | 279.472 | 276.737 | 269.829 | 290.248 |
| | | 21,225 | Fixed Cost/ Mw/m | 30,593 | 28,286 | 26,534 | 25,120 | 27,070 | 23,799 |
| | | 31,096 | Fixed Cost plus Dep'n/ Mw/m | 73,684 | 73,087 | 69,847 | 70,571 | 82,921 | 77,934 |
| | | 29,389 | Fixed Cost plus Dep'n & Int./Mw/m | 69,886 | 65,363 | 60,280 | 59,244 | 68,876 | 65,011 |
| | 12.5% | 3.6% | Operating Income to Sales - % | -8.0% | 12.5% | 13.3% | 14.3% | 13.4% | 17.2% |
| | | | Operating Income to Gross Assets in Service (Average) - %: | | | | | | |
| | | 14.9% | - historical | | | | | | |
| | 1.8% | 1.9% | - revalued | -1.9% | 3.0% | 3.1% | 3.1% | 2.7% | 3.2% |
| | 3.0% | 3.1% | Operating Income/ Net Assets - % | -3.6% | 6.1% | 6.4% | 6.2% | 5.3% | 6.1% |
| | | | **BALANCE SHEET RATIOS** | | | | | | |
| | | 2.1 | Current Ratio | -0.5 | -2.3 | 1.0 | 0.6 | 0.3 | 0.2 |
| | | 0.3 | Cash at Bank to Sales - months | 0.3 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| | | 20 | Accts Receivable to Sales - days | 20 | 20 | 20 | 20 | 20 | 20 |
| | | | Debt to Equity Ratio - % | | | | | | |
| | | | - historical | | | | | | |
| | | | - revalued | 7.8% | 9.7% | 11.6% | 12.2% | 16.4% | 16.6% |

Billions Zloty at Base Year Prices
Case: gencobas\system_v\grouplig

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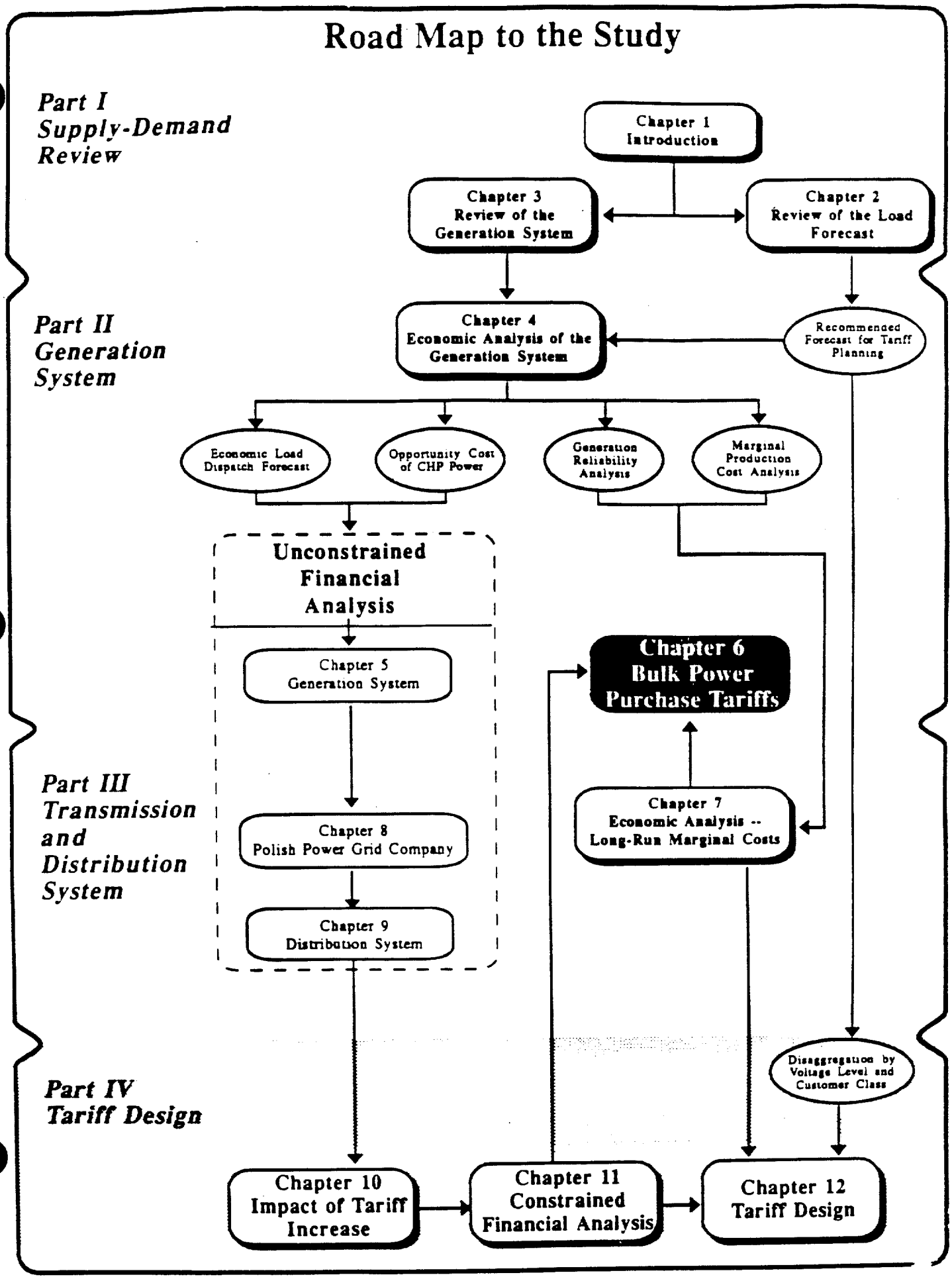
# Road Map to the Study

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administer, it is possible that a better total power price from a generator could result if a two-part tariff would facilitate better financing terms for the plant.

### Dispatch Flexibility

The total avoided cost of energy should be the ceiling of the willingness of PPGC to pay for power that would be entirely under its control. Less control or flexibility in the dispatch of that power should result in a lower price.

In the computation of DRR assumptions must be made regarding the split of CHP power between base and peak. That is, some of the energy from CHP is assumed to be associated with a constant power output, while some can be flexibly dispatched and therefore generated during the peak hours. To the extent that CHP plants are willing to accept more flexibility in the dispatch, these assumptions could be changed and the resulting avoided costs would be slightly higher.

## 6.2 COST-BASED PRICING

It is recommended that cost based pricing apply to all existing conventional power plants that are dedicated primarily to power production. This would include plants involved in minor sales of heat, as described earlier.

The compensation should be based on a two-part tariff. Fixed costs would be recovered through capacity sales and variable costs through energy sales. In addition, profit, calculated as a return on net assets, should be included in the tariff. It is recommended that most of this return (85 percent) be collected through capacity sales with a small part (15 percent) collected through energy sales.

### 6.2.1 Standard Cost Phase-In

Standard costs should be established for both fixed and variable cost components. Fixed-cost standards should cover the wages of plant personnel, administrative costs, and plant maintenance. Variable-cost standards should apply to fuel, variable operating costs, and costs for use of the environment.

To facilitate the transition to standard costs, a phase-in period can be established. During this period, partial recovery will be allowed of costs incurred above standards and, similarly, a partial withholding of an equal fraction of any the windfall profits of power plants that operate at costs below standard. The need for this adjustment may be eliminated by revised grouping of thermal plants into generating utilities as discussed in Chapter 5.

The actual selection of standard costs for each component should be the subject of a detailed analysis, but we offer recommendations on the principles for the treatment of fixed costs of non-essential capacity and basic principles for determining standard costs for fuel and the use of the environment.

### 6.2.2 Non-Essential Capacity

While the current excess generating capacity is not the result of poor planning by the power sector, it is nonetheless its responsibility. Therefore, generating utilities should be allowed to recover the fixed costs of such capacity from the ratepayers. On the other hand, it is necessary to provide a signal to the generating utilities that such capacity is not of value to the system at present and that it is within their managerial responsibility to decide whether to retire excess capacity or maintain it for future capacity sales.

One option is to allow the recovery of standard fixed costs while not providing any return on assets for non-ordered capacity. This option will not provide a significant saving since the capacity in question generally is installed in the older plants and their return on net revalued assets is very small.

A second option is to reduce the standard fixed cost allowance by application of a factor that is uniform for all non-essential capacity and related to the period of time until such capacity will become essential. This is being done at present except that the factor is not uniform (it is related to the specific plant).

A third option is to compute the value of the current capacity by performing a differential revenue requirements analysis. (A similar option is discussed later in this chapter with respect to CHP plants.)

### 6.2.3 Standard Fuel Cost

We recommended that fuel costs for coal-fired conventional grid plants be recovered on the basis of the border price of coal of a standard quality burned at the efficiency declared by the plant to the central dispatch. The standard cost of lignite should be pegged to the border price of coal through a formula that includes the estimated additional cost of burning lignite at the same level of emissions as that of standard-quality coal.

It is reasonable to use the heat rate declared by each powerplant in the formula that relates the actual energy purchases to the fuel cost compensation at standard fuel price. In this situation, the order of merit dispatch will be strictly based on increasing heat rate for each type of fuel. Any increment in the declared heat rate above its actual value would simply result in lower energy purchases and therefore lower profit. Hence, it could be economically sound to allow powerplants to compete against each other in the declaration of heat rate to the central dispatch.

### 6.2.4 Allowance for Environmental Tax Recovery

In principle, we would prefer that no environmental tax be levied against plants that meet target emission levels set by the Polish Government and that, eventually, only plants meeting these targets be allowed to sell power. However, since this policy may not be within the control of the power sector, a system needs to be established to allow the recovery of these costs in a way that would promote fair internal prices for fuels of different qualities and reduce overall emissions.

It is recommended that recovery of environmental costs be allowed up to the amount that would be levied if the plant were burning fuel of the standard quality used as a reference for setting border price of coal. Any additional costs would not be recoverable. Thus, a system of internal fuel prices would develop in the coal market to offset the environmental costs which can not be recovered when lower quality fuel is burned. Furthermore, any emissions reduced below the standard will result in additional profit to the generating company thereby giving further incentives for clean air production.

Two important issues must be addressed in the allowance for recovery of environmental tax: 1) the recovery of the cost of environmental control equipment and 2) the effect of environmental tax on the order of merit dispatch.

### Recovery of the Cost of Environmental Control

Accepting that emission standards are a matter of Government policy, it is entirely reasonable to allow for recovery of any capital and operating costs incurred to meet those standards and to allow a return on the additional value of net assets. It is also reasonable to develop a different operating cost standard to cover the cost of chemicals and other operating expenses associated with emission control equipment.

In general, it should be attractive for any powerplant to eliminate non-recoverable emissions costs if requisite investments are fully recoverable and even profitable. It is important to establish that, once the environmental control equipment is in operation, then the equivalent level of emissions for fuel of standard quality also drops. Thus switching to a cheaper (and dirtier) fuel will not be very attractive. In other words, the ratepayers should pay for investments and costs that result in actual improvement to the quality of the environment and not for investments that increase profit to the plants at the same environmental quality level.

### Dispatch Order

As a general rule, environmental taxes should not be included as economic costs when calculating order of merit dispatch. Taxes are transfer payments within society, and as such they are not treated as economic costs.

Environmental costs should be included as economic costs if they represent quantified measures of impact to society. Specifically, these charges should be directly related to: 1) the quantity of pollutants emitted, and 2) the cost to society of either reducing emissions or of living with them.

Including environmental taxes in the dispatch could cause lignite-fired plants to move above the base in the merit dispatch, significantly distorting the intended use of these plants and increasing the total cost of power generation. Therefore, we recommend that environmental costs should be included only to the extent that they represent explicit costs to society.

### 6.2.5 Heat Sales by Power Plants

The sale of heat by plants primarily dedicated to power production is economically efficient to both the heat and the power subsectors and this activity must therefore be encouraged. These plants will be compensated according to the cost based principles discussed above, including the recovery of the additional cost of producing heat for sale. However, the revenues from the sale of heat should be applied against costs to be recovered. In order to provide an incentive for sales of heat from powerplants, these plants may be allowed a regulated rate of return on such sales so long as the regulator is satisfied that revenues from heat sales offset the additional costs.

## 6.3 VALUE-BASED PRICING

There are many resources in the system that are not entirely under the control of central dispatch or that have constraints that prevent their dispatch on an economic basis. Resources that may have this characteristics are combined heat and power plants, small hydroelectric plants and surplus power from autoproducers. Many of these resources may sell their power directly to distribution companies at negotiated prices but in some cases power will be sold to the grid and thus the price should be determined either through bidding or negotiated not to exceed the minimum cost that would be incurred to secure such power supply from an alternative source. This approach to evaluating power is known as the "avoided cost principle" and there are many methods and techniques applied all over the world to compute avoided costs.

As discussed in Chapter 4, the computation of avoided cost may in some cases yield similar results to that of marginal costs but the former takes into account the characteristics of the power being supplied (i.e. capacity and capacity factor) whereas the later assumes that power is supplied at load factor and very small increments.

## 6.4 COMPUTATION OF AVOIDED COSTS FOR CHP, SMALL HYDRO AND AUTOPRODUCERS

While the joint production of heat and power is economically efficient and should be encouraged, a cost based compensation for power is not recommended for plants that are not primarily operated for power production as is the case of CHP plants in Poland.

Due to the relatively small share of CHP in total power production and the social priority placed on adequate and economic heat supply, it is preferable to transfer to district heating customers the full benefit of the cogeneration process as recommended in the district heating tariff study (DBDH, August 1992). Purchase of electricity from CHP plants based on the principle of avoided costs eliminates the need to allocate costs between the joint products of heat and electricity.

Small hydro plants and autoproducers are mostly outside the control of central dispatch and, at any rate, produce to little power to engage in individual pricing formulas based on their production cost. It is therefore preferable to apply avoided cost principles to these resources.

Since different resources have different characteristics the computation of avoided cost should be done individually for each resource under negotiation. However, in order to provide a reference value, it is illustrative to present a computation of the combined avoided cost of all CHP, small hydro and autoproducers.

### 6.4.1 Least-Cost Expansion Plans

The GPT model described before and used for the long term simulation of the system has a very convenient feature that is particularly useful to estimate the approximate least cost of expanding the system. Faced with a situation when capacity reserve is below a target level GPT will choose from a selection of different resources those that will minimize the capital and operating costs for each year.

This method generally results in expansion plans that are not continuously feasible and are slightly lower in cost than that of the true feasible least cost plan but the difference in cost between two approximate plans is very close to the difference in cost between two true lest cost plans and thus the method is well suited for avoided cost calculations.

In this case GPT was allowed to choose resources from three possible candidates. A 360 MW lignite fired steam turbine unit, a 600 MW coal fired steam turbine unit and a 120 MW gas turbine fired with natural gas. These candidate resources were also used by PPGC in the analysis of the expansion plan and the same characteristics and costs were adopted. The



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need for capacity is defined by a target of zero effective capacity reserve which results in adequate installed capacity reserve levels.

The model was run twice under identical conditions for the period 1992-2010 with the only difference being that in the second run (evaluation case) all CHP, small hydro and autoproducers are eliminated from the planned system (base case). A summary of the capacity additions chosen for some spot years follows:

**Capacity Additions in MW**

| Year | Base Case | | | Evaluation Case | | |
|---|---|---|---|---|---|---|
| | Lignite | Coal | Gas Turbine | Lignite | Coal | Gas Turbine |
| 1995 | 0 | 0 | 720 | 0 | 0 | 4,560 |
| 2000 | 0 | 0 | 120 | 0 | 0 | 6,840 |
| 2005 | 0 | 0 | 1,680 | 1,440 | 6,960 | 2,400 |
| 2010 | 360 | 1,200 | 1,200 | 2,880 | 4,800 | 6,600 |

It is stressed that the additions shown for the two plans are only meaningful in the context of an analysis of differential costs and not at all in absolute terms. For instance, the addition of 720 MW of gas turbines in 1995 is to compensate for capacity undergoing rehabilitation. Similarly, the drop in peaking capacity (gas turbines) through time in favor of base load capacity (lignite and coal) is not really feasible. On the other hand, the reliability of these ideal sequences is much closer than can normally be expected of truly feasible sequences and thus their costs are more readily comparable.

### 6.4.2 Annual Avoided Costs

In Exhibit 6-1 it is shown, for each of these two cases, the annual capacity and production of all CHP, hydro and autoproducers and the fixed cost (capital and operation) and variable cost (fuel) of the entire generation system. The capacity and production of hydro in the evaluation case corresponds to resources not being evaluated such as pumped storage hydroelectric.

# EXHIBIT 6–1

## COMBINED AVOIDED COST OF CHP, SMALL HYDRO AND AUTOPRODUCERS

| YEAR | BASE CASE EXPANSION ANNUAL VALUES | | | | EVALUATION CASE EXPANSION ANNUAL VALUES | | | | GENERATION AVOIDED COSTS ANNUAL UNIT VALUES | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | CHP+H+AP CAPACITY MW | CHP+H+AP PRODUCTION GWH | FIXED COSTS M$ | VARIABLE COSTS M$ | CHP+H+AP CAPACITY MW | CHP+H+AP PRODUCTION GWH | FIXED COSTS M$ | VARIABLE COSTS M$ | CAPACITY $/kW-Y | CAPACITY CTS/kWh | ENERGY CTS/kWh | TOTAL CTS/kWh |
| 1992 | 7041 | 14630.2 | 473.4 | 2044.8 | 1330 | 326.7 | 729.3 | 2465.8 | 44.81 | 1.79 | 2.94 | 4.73 |
| 1993 | 7091 | 16477.8 | 499.8 | 2085.3 | 1330 | 1844.4 | 771.6 | 2539.6 | 47.18 | 1.86 | 3.10 | 4.96 |
| 1994 | 7191 | 15658.3 | 514.0 | 2168.3 | 1330 | 358.9 | 801.6 | 2665.2 | 49.07 | 1.88 | 3.25 | 5.13 |
| 1995 | 7341 | 16494.7 | 514.8 | 2218.3 | 1330 | 208.4 | 810.4 | 2747.6 | 49.18 | 1.82 | 3.25 | 5.06 |
| 1996 | 7531 | 17786.9 | 484.0 | 2206.4 | 1330 | 204.8 | 787.6 | 2777.6 | 48.96 | 1.73 | 3.25 | 4.98 |
| 1997 | 7871 | 20024.4 | 480.7 | 2223.7 | 1330 | 173.9 | 808.1 | 2864.5 | 50.05 | 1.65 | 3.23 | 4.88 |
| 1998 | 9061 | 23892.4 | 614.2 | 2218.4 | 2080 | 1124 | 941.5 | 2987.7 | 46.88 | 1.44 | 3.38 | 4.82 |
| 1999 | 9161 | 24516.8 | 627.1 | 2296.9 | 2080 | 1088.3 | 986.2 | 3136.7 | 50.71 | 1.53 | 3.58 | 5.12 |
| 2000 | 9681 | 27952.1 | 618.2 | 2300.2 | 2080 | 1050.4 | 1017.0 | 3293.1 | 52.47 | 1.48 | 3.69 | 5.17 |
| 2001 | 9981 | 29954.9 | 611.9 | 2217.9 | 2080 | 1023.9 | 1034.5 | 3276.2 | 53.49 | 1.46 | 3.66 | 5.12 |
| 2002 | 10281 | 31906.4 | 638.0 | 2307.8 | 2080 | 986.1 | 1092.3 | 3493.2 | 55.40 | 1.47 | 3.83 | 5.30 |
| 2003 | 10581 | 33884.4 | 660.0 | 2391.6 | 2080 | 960.3 | 1258.7 | 3603.5 | 70.43 | 1.82 | 3.68 | 5.50 |
| 2004 | 10881 | 35785.4 | 695.5 | 2509.4 | 2080 | 914.5 | 1559.9 | 3594.7 | 98.22 | 2.48 | 3.11 | 5.59 |
| 2005 | 11181 | 37808.7 | 713.1 | 2592.1 | 2080 | 879.3 | 1807.5 | 3605.0 | 120.25 | 2.96 | 2.74 | 5.71 |
| 2006 | 11481 | 39720.3 | 744.8 | 2717.9 | 2080 | 823.8 | 1997.4 | 3680.5 | 133.24 | 3.22 | 2.47 | 5.70 |
| 2007 | 11781 | 41688.6 | 800.1 | 2695.5 | 2080 | 777.8 | 2028.1 | 3821.4 | 126.58 | 3.00 | 2.75 | 5.75 |
| 2008 | 12081 | 43608.6 | 754.2 | 2828.4 | 2080 | 710.7 | 2148.2 | 3910.7 | 139.39 | 3.25 | 2.52 | 5.77 |
| 2009 | 12381 | 45539.2 | 863.9 | 2875.2 | 2080 | 681.2 | 2402.3 | 3933.4 | 149.34 | 3.43 | 2.36 | 5.79 |
| 2010 | 12851 | 48822 | 1071.2 | 2816.2 | 2080 | 629.6 | 2600.0 | 4018.7 | 141.94 | 3.17 | 2.50 | 5.67 |

The difference in fixed costs divided by the difference in capacity is the fixed avoided cost per unit of capacity of each year and the difference in variable costs divided by the difference in production is the variable avoided cost per unit of energy of each year. The total avoided cost per unit of energy is the difference between all costs divided by the difference in production. The fixed avoided cost can, of course, also be expressed per unit of energy.

### 6.4.3 Levelized Avoided Costs

The unit annual avoided costs are rather unstable because they react to short term system circumstances. It is normally preferable to use levelized values over a period of time, generally corresponding to contract term, as a basis for a power purchase agreement. Sometimes part of the price is levelized while another part, usually the fuel component, remains annually variable.

In Exhibit 6-2 the results of the two cases are shown in the form of accumulated discounted values for each year and the computation of unit levelized values of avoided costs is done using these accumulated discounted values exactly in the same way that the unit annual values were used in Exhibit 6-1. This is the correct method of obtaining levelized unit avoided costs (or any levelized unit cost for that matter) and is not the same as levelizing the annual unit avoided costs.

The tendency for avoided costs to increase is due to several factors. The avoided fixed costs per unit of capacity increase as the excess reserve in the system disappears towards 1997/98. After 2000 it continues to increase as the replacement generation becomes more mixed between base load and peaking plants. The variable costs vary very little and only as a result of different generation mix through the years and the small but constant increase in the price of gas.

### 6.4.4 Proxy Plant Methods

It is often considered advantageous to define avoided cost in terms of an alternative or "proxy" resource. Thus, any changes in fuel prices or other costs can be captured directly by the response of the proxy resource to the new cost inputs.

The most likely proxy plant for compensating CHP power in Poland is a conventional coal fired steam plant. A reasonable agreement would involve energy payments based on the equivalent cost of energy produced by a coal fired steam turbine and capacity payments based on the unit capacity cost of a coal fired steam turbine plant applied to the alternative capacity that the CHP system is actually avoiding. The amount of "avoided capacity" can again be

# EXHIBIT 6-2

## COMBINED AVOIDED COST OF CHP, SMALL HYDRO AND AUTOPRODUCERS

| YEAR | BASE CASE EXPANSION ACCUMULATED PRESENT VALUES | | | | EVALUATION CASE EXPANSION ACCUMULATED PRESENT VALUES | | | | GENERATION AVOIDED COSTS LEVELIZED UNIT VALUES (1992 YEAR) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | CHP+H+AP CAPACITY MW | CHP+H+AP PRODUCTION GWH | FIXED COSTS M$ | VARIABLE COSTS M$ | CHP+H+AP CAPACITY MW | CHP+H+AP PRODUCTION GWH | FIXED COSTS M$ | VARIABLE COSTS M$ | CAPACITY $/kW-Y | CAPACITY CTS/kWh | ENERGY CTS/kWh | TOTAL CTS/kWh |
| 1992 | 7041.0 | 14630.2 | 473.4 | 2044.8 | 1330.0 | 326.7 | 729.3 | 2465.8 | 44.81 | 1.79 | 2.94 | 4.73 |
| 1993 | 13372.3 | 29342.5 | 919.7 | 3906.7 | 2517.5 | 1973.5 | 1418.2 | 4733.3 | 45.93 | 1.82 | 3.02 | 4.84 |
| 1994 | 19104.9 | 41825.2 | 1329.4 | 5635.2 | 3577.8 | 2259.6 | 2057.3 | 6858.0 | 46.88 | 1.84 | 3.09 | 4.93 |
| 1995 | 24330.0 | 53565.8 | 1695.8 | 7214.2 | 4524.4 | 2407.9 | 2634.1 | 8813.7 | 47.37 | 1.83 | 3.13 | 4.96 |
| 1996 | 29116.1 | 64869.7 | 2003.4 | 8616.4 | 5369.7 | 2538.1 | 3134.6 | 10578.9 | 47.64 | 1.81 | 3.15 | 4.96 |
| 1997 | 33582.4 | 76232.1 | 2276.2 | 9878.2 | 6124.4 | 2636.8 | 3593.2 | 12204.3 | 47.96 | 1.79 | 3.16 | 4.95 |
| 1998 | 38172.9 | 88336.7 | 2587.4 | 11002.1 | 7178.1 | 3206.2 | 4070.2 | 13717.9 | 47.84 | 1.74 | 3.19 | 4.93 |
| 1999 | 42316.9 | 99426.9 | 2871.0 | 12041.1 | 8119.0 | 3698.5 | 4516.3 | 15136.8 | 48.11 | 1.72 | 3.23 | 4.95 |
| 2000 | 46226.9 | 110716.3 | 3120.7 | 12970.1 | 8959.1 | 4122.7 | 4927.0 | 16466.9 | 48.47 | 1.69 | 3.28 | 4.98 |
| 2001 | 49826.2 | 121518.3 | 3341.4 | 13769.9 | 9709.2 | 4492.0 | 5300.1 | 17648.3 | 48.82 | 1.67 | 3.31 | 4.99 |
| 2002 | 53136.4 | 131791.3 | 3546.8 | 14512.9 | 10378.9 | 4809.5 | 5651.7 | 18773.0 | 49.23 | 1.66 | 3.35 | 5.01 |
| 2003 | 56178.1 | 141532.3 | 3736.5 | 15200.5 | 10976.8 | 5085.5 | 6013.6 | 19808.9 | 50.38 | 1.67 | 3.38 | 5.05 |
| 2004 | 58971.0 | 150717.5 | 3915.0 | 15844.6 | 11510.7 | 5320.3 | 6414.0 | 20731.6 | 52.65 | 1.72 | 3.36 | 5.08 |
| 2005 | 61533.4 | 159382.3 | 4078.5 | 16438.6 | 11987.4 | 5521.8 | 6828.2 | 21557.8 | 55.50 | 1.79 | 3.33 | 5.11 |
| 2006 | 63882.7 | 167509.8 | 4230.9 | 16994.7 | 12413.0 | 5690.3 | 7236.9 | 22310.9 | 58.40 | 1.86 | 3.29 | 5.14 |
| 2007 | 66035.0 | 175126.2 | 4377.0 | 17487.2 | 12793.0 | 5832.4 | 7607.4 | 23009.0 | 60.67 | 1.91 | 3.26 | 5.17 |
| 2008 | 68005.7 | 182239.7 | 4500.1 | 17948.6 | 13132.3 | 5948.4 | 7957.9 | 23646.9 | 63.01 | 1.96 | 3.23 | 5.19 |
| 2009 | 69808.9 | 188872.2 | 4625.9 | 18367.3 | 13435.2 | 6047.6 | 8307.7 | 24219.8 | 65.31 | 2.01 | 3.20 | 5.22 |
| 2010 | 71480.0 | 195221.0 | 4765.2 | 18733.5 | 13705.7 | 6129.5 | 8645.9 | 24742.4 | 67.17 | 2.05 | 3.18 | 5.23 |

BASE YEAR 1992

DISCOUNT RATE: 12.00%

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determined directly from system expansion plans with and without the CHP component or more simply from the capacity needed to maintain adequate capacity reserve margin if the CHP component were not there.

Alternative proxy plant methods can be used to provide an incentive for generation at times of highest system cost. For instance, energy sold at peak can be compensated at the cost of gas turbine generation while energy sold off-peak can be compensated at the cost of steam turbine generation. This mode may be interesting for new resources entering the system beyond 1997 but the additional complexity is not justified for existing resources.

## 6.5 BULK PURCHASE POWER STRUCTURE

It is important to maintain the LRMC structure at the retail and perhaps at the bulk sales tariff level in order to give consumers correct signals about the cost of supplying electricity. At the power purchase level these signals are only relevant to value based compensation system since the economic dispatch will assure the efficient utilization of the cost based resources.

### Time-of-Day Tariff for CHP

There could be economic advantages for PPGC to structure its bulk purchase tariff in line with its bulk sales tariff. For instance, when time-of-day tariffs are offered to distribution companies it makes sense to offer CHP plants a time-of-day compensation on the variable portion of avoided costs.

This can be structured on the basis of the hourly short run marginal costs (SRMC) discussed in Chapter 4 but the differential SRMC between peak and off-peak up to 1997 is fairly small, only 8 percent. Thus it is unlikely that a time-of-day tariff for CHP would be justified in the next few years. Once gas turbines exist in the system the differential SRMC could be much greater and a time-of-day tariff will certainly be advantageous. This time-of-day tariff may be agreed on the basis of the SRMC structure or by developing a two part energy proxy plant as discussed in 6.4.2 above.

### One-Part or Two-Part Tariff

At the generation level the issue of one-part or two-part tariff has more to do with project financing and risk management than with economics and is therefore a matter of negotiation. For instance, while a one part tariff based on energy delivered may be simpler for PPGC to

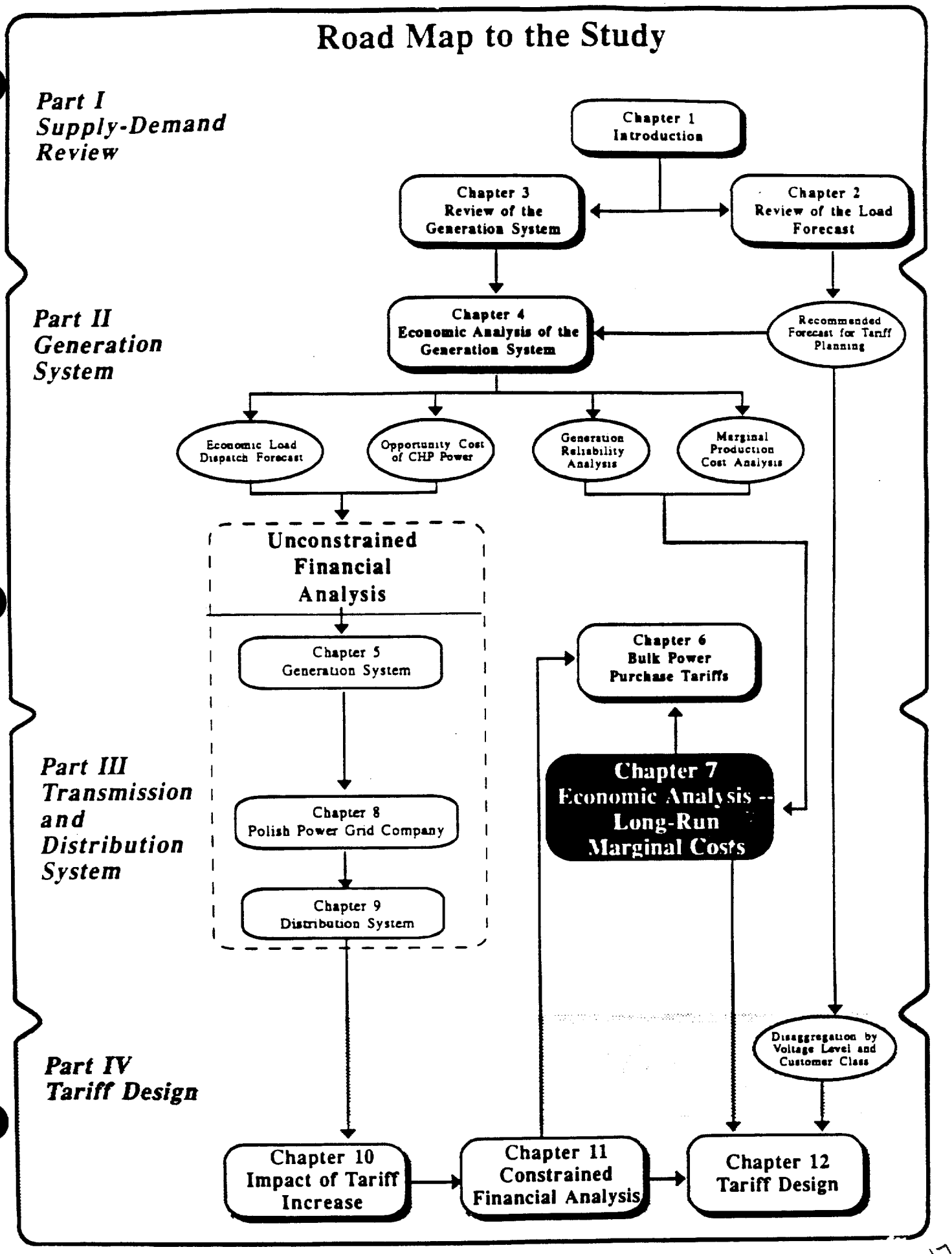
administer, it is possible that a better total power price from a generator could result if a two-part tariff would facilitate better financing terms for the plant.

### Dispatch Flexibility

The total avoided cost of energy should be the ceiling of the willingness of PPGC to pay for power that would be entirely under its control. Less control or flexibility in the dispatch of that power should result in a lower price.

In the computation of DRR assumptions must be made regarding the split of CHP power between base and peak. That is, some of the energy from CHP is assumed to be associated with a constant power output, while some can be flexibly dispatched and therefore generated during the peak hours. To the extent that CHP plants are willing to accept more flexibility in the dispatch, these assumptions could be changed and the resulting avoided costs would be slightly higher.

# Road Map to the Study

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# CHAPTER 7: ECONOMIC ANALYSIS - LONG-RUN MARGINAL COSTS

This chapter describes the methodology employed and the analysis undertaken to estimate long-run marginal costs (LRMCs) for the Polish power system. These estimates provide the necessary economic benchmark and establish the point of departure in tariff design that are required to accommodate financial and equity objectives. Specifically, average tariff yield is governed by the financial revenue requirement, whereas the allocation of this revenue responsibility by customer class and the individual customer class tariff structure are affected by the LRMC structure.

The chapter is organized as follows. Section 7.1 describes the overall marginal cost methodology. Section 7.2 illustrates the application of this methodology through the use of an LRMC computer model tailored specifically to Poland. This section contains actual model printouts and results. Section 7.3 discusses the sensitivity of the results to alternative modeling assumptions.

## 7.1 OBJECTIVES AND APPROACH

The efficiency pricing objective in electricity tariff planning is embedded in the economic theory of efficient allocation of resources and can be theoretically linked to the marginal cost structure of the supply system. These costs typically vary by service voltage level and by time of day, and spatial characteristics in cost structure may exist due to differential losses.

Put very simply, the marginal cost of electricity represents the cost of an increment of demand. While there are different interpretations of marginal cost, the alternative definitions are similar in that they are all forward looking. They consider only future costs related to future output, as opposed to embedded cost-of-service methods.

The rationale for marginal cost pricing emanates from the economic theory of efficient allocation of resources in competitive markets. Prices that are equal to marginal cost provide the correct signals to decision-makers -- producers and consumers -- and should result in a market equilibrium at a level and pattern of electricity supply that provide for the most efficient allocation of scarce resources.

Long-run marginal cost can be defined as the incremental costs of all adjustments in the system development plan and system operations that are attributable to an incremental increase in demand that is sustained indefinitely into the future. LRMC pricing emphasizes the trade-off between the need to give correct signals and the importance of prices that are

relatively stable over time. While short-run marginal costs (SRMC)[1] might provide even greater allocative efficiency at any given time, tariff policy-makers, producers, and consumers generally prefer a reasonable degree of price predictability and stability in order to facilitate long-term planning. A long-run perspective also reflects the long-term effects of the changing costs of electricity supply. Ignoring such effects can result in consumers making sub-optimal decisions with regard to long-term investments.

## 7.2 LONG-RUN MARGINAL COST PRICING MODEL AND RESULTS

For this study, a PC-based model was developed and adapted to estimate marginal costs for the Polish power system. Illustrative model results and their implications are discussed in detail in the following sections. Briefly, the model's structure embodies the theoretical considerations outlined in the preceding discussion and facilitates the calculation of marginal energy costs for up to three rating periods (peak, mid-peak, and off-peak). In addition, the model incorporates the calculations necessary to estimate marginal generation capacity cost utilizing the peaker method, and as a user option affords the same calculation using the next-plant method.[2] Also contained in the model are calculations of long-run average incremental costs (LRAIC) for various network voltage levels selected by the user.

It should be noted that the model calculates long-run marginal costs in "border prices." These are the world market prices of the goods and services (delivered to the Polish border) needed to provide marginal energy and capacity. Border prices exclude the effects of taxes, duties and subsidies that distort the prices of these goods in the domestic market.

A standard conversion factor (SCF) is used to adjust the costs of local goods to border prices in the model. This factor has been approximated as 1.0 (i.e., no adjustment).[3] A foreign conversion factor is included in the model in order to account for the average duties/taxes on imported equipment; this factor is assumed to be 1.00 because taxes and duties are excluded from all cost streams. A local labor conversion factor is also included in the model to adjust for cases in which the opportunity cost of domestic labor employed on power projects diverges from its market wage. We have not applied this factor in Poland because local labor was not separated in the cost streams. After LRMCs are calculated at border prices,

[1] Short-run marginal cost can be defined as the variable fuel and O&M cost ("system lambda") of the generating unit providing marginal energy, plus outage costs (also known as "congestion costs").

[2] Estimates from the second approach serve as a useful point of comparison. As noted later in this chapter, the next-plant method is less relevant for the current Polish situation of excess baseload capacity.

[3] The SCF is defined as the official exchange rate divided by the shadow exchange rate (OER/SER); an SCF of 1.0 implies a shadow exchange rate equal to the market exchange rate of 13,400 Zl/US dollar (mid-1992).

they are finally restated at domestic prices (using the same SCF) to derive appropriate LRMCs at market efficiency prices. Of course, with an SCF of 1.0, there is no adjustment.

Cash flows in future years are discounted back to the study year by applying a 12 percent real discount rate. The discount rate level was defined in discussions with international agencies and Polish planning authorities; it represents the opportunity cost of capital for the economy as a whole as presumed that the weighted average return on all the possible sources to finance for future investment in Poland. This choice is justified on the basis that capital markets reflect all we need to know about the productivity of capital and the preferences of consumers, whose utilities in turn ought to form the basis for social choice. Just as a private firm seeks to maximize profits, the national economy's goal is to maximize growth of net output. It should not, therefore, undertake any project which does not at least achieve its weighted average opportunity cost of capital.

In order to parallel the logical flow of the LRMC model, the remainder of this section is organized into four subsections:

- marginal energy cost
- marginal generation capacity cost
- marginal network capacity cost
- results.

The first three sections demonstrate how the model uses basic assumptions about the system to calculate energy (Zl/kWh) and capacity (Zl/kW) costs. The results section presents the additional calculations required to integrate these component costs into the model's estimation of the long-run marginal cost of electricity delivered to different voltages and tariff classes.

### Marginal Energy Cost

The first component is essentially the variable cost (fuel and variable O&M) of the most expensive generating unit that is running for the purpose of "picking up incremental load at the margin." Once this plant is identified, the marginal energy cost at that instant can be calculated directly given the unit fuel price, heat content of the fuel, and the incremental heat rate of the generating unit.

Exhibit 7-1 helps to illustrate the concept of marginal energy cost and its variation by time-of-day (TOD). The exhibit depicts a schematic of a typical winter daily load curve for the Polish power grid. Also shown in the exhibit is a 1997 merit order stacking of generating units classified into seven homogeneous groups, ranked from the cheapest to the most expensive fuel group. At the bottom (i.e., the first to be dispatched) is the base hydro

energy. The variable cost of operation for this group is essentially any non-fuel variable O&M expense. Therefore, the total variable cost for this group is close to zero.

Stacked immediately above the base hydro are the combined heat and power (CHP) units expected to be in the system by 1997. These units are not stacked in "merit order" due to lower cost, but rather because the system is obligated to purchase the energy produced as part of the nation's district heating system. Next in the stack come the lignite units. The variable cost of lignite-fired energy is estimated to be 218.7 Zl/kWh. As one goes higher up in the stacking order, the variable (fuel plus other O&M) costs become progressively higher.

Stacked immediately above the lignite units are the coal units. We have divided these into two groups. "Coal-1" includes the majority of coal-fired capacity; the variable cost of energy of these more efficient units is estimated to be 272.5 Zl/kWh. "Coal-2" generally includes the oldest, smallest, and least-efficient coal-fired units, with an estimated variable cost of 302.9 Zl/kWh. Following the coal units in the stacking order is the peaking energy from combustion turbines, with an estimated variable cost of 591.5 Zl/kWh.

A production simulation model (GPT) was utilized to determine the optimal stacking presented in Exhibit 7-1, and a short-marginal cost model was used to determine, *on a probabilistic basis*, the units that can be expected to be at the margin at different hours of the day in summer and winter. These models are described in Chapter 4. Surprisingly, the 240 MW of combustion turbine capacity installed by 1997 are not expected to provide marginal energy, even during peak winter hours; these units are part of the least-cost expansion plan to provide reliability support, as highlighted by the very low capacity utilization of combustion turbines shown in Exhibit 7-1. Rather, marginal energy during both seasons and during all hours of the day is provided by coal-fired steam generating units.

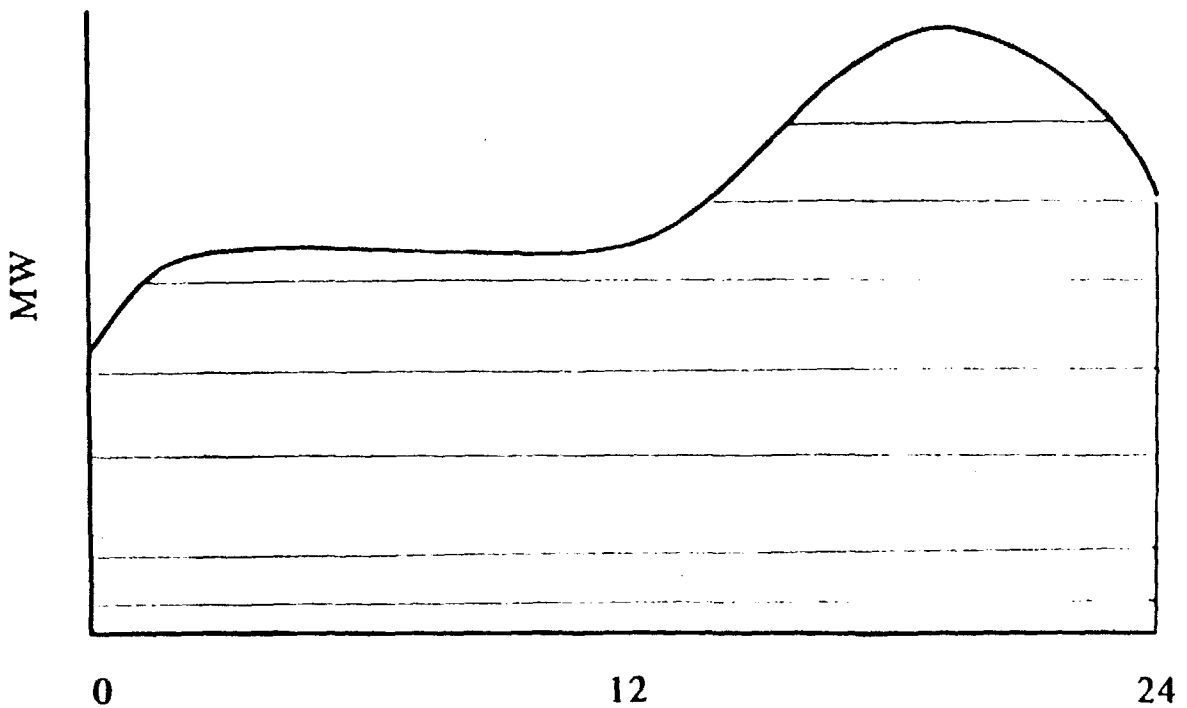
For the purposes of estimating long-run marginal energy costs by season and time of day, the following data were reviewed:

- projected load resource balances (MW) through the year 2006
- system dispatch (GWh generation by fuel type) at present and projected for the future
- production costing simulations for the next 15 years, focusing on the year 1997,[4] estimating the capacity utilization and average energy production by generating unit

[4] We selected the year 1997 as a representative snapshot of system characteristics and conditions for the purpose of estimating long-run marginal costs.

Exhibit 7-1

# Typical Day Winter Load Curve and 1997 "Merit Order" Stacking of Marginal Plants




| Variable Cost (Z/kWh) by Plant Group | |
|---|---|
| Pumped Storage | -- |
| Combined Turbines | 591.5 |
| Coal -2 | 302.9 |
| Coal -1 | 272.5 |
| Lignite | 218.7 |
| CHP | -- |
| Base Hydro | -- |

- system hourly load data for the last several years.

In addition, a separate analysis was conducted to identify those hours of each day that contribute most towards the annual loss-of-load probability (LOLP). Based on LOLP, the peak, mid-peak, and off-peak periods have been identified.

These analyses, detailed in Chapter 4, are the basis for the following assumptions applied to estimate marginal energy costs:

- distinct seasonal difference in both supply and demand distinguish summer (May through October) and winter (November through April) periods

- Time of day rating periods:

  -- Winter: A peak period of 4:00 p.m. to 9:00 p.m. on weekdays, and a mid-peak period of 7:00 a.m. to 1:00 p.m. on weekdays, with all other times off-peak

  -- Summer: A peak period of 7:00 p.m. to 10:00 p.m. on weekdays, and a mid-peak period of 7:00 a.m. to 1:00 p.m. on weekdays, with all other times off-peak

- Fuel costs used in the marginal energy cost analysis are summarized below. (Fuel price issues are elaborated in Chapter 3 and in Appendix 3.2.)

| Fuel Cost | $/GJ | TysZl/GJ |
|---|---|---|
| Coal | 2.01 | 26.940 |
| Lignite | 1.53 | 20.470 |
| Mazout | 2.07 | 27.610 |
| Gas/Distillate | 3.65 | 49.050 |

- The following table summarizes the marginal costs derived from the production simulation analysis for 1997. The table identifies "proxy" coal-fired units whose variable costs closely approximate the calculated marginal costs. These proxies have been applied in the LRMC model to define marginal energy costs.

- Note that marginal energy costs are higher in the Summer than during the Winter for mid-peak and off-peak rating periods. As discussed in Chapter 4, this surprising result follows from the fact that less capacity is available during

the Summer months (e.g., shutdown of CHP units) and maintenance scheduling requires utilization of older, less efficient generating units.

| Season/ Time of Day | Marginal Energy Cost ($/kWh) | Proxy Unit (MW) |
|---|---|---|
| Summer | | |
| Peak | 4.64 | Gas Turbine |
| Mid-Peak | 3.97 | -[5] |
| Off-Peak | 2.12 | Jaworzno 3 (200) |
| Winter | | |
| Peak | 4.64 | Gas Turbine |
| Mid-Peak | 2.80 | Jaworzno 1 (19) |
| Off-Peak | 2.07 | Rybnik (200) |

Exhibit 7-2, taken from the LRMC model, summarizes the results and specific assumptions used in calculating marginal energy costs: heat rate, fuel types, heat content, variable O&M expenses, etc. for the marginal plants during on-peak and off-peak hours. The exhibit indicates that marginal energy costs are determined as fuel and O&M costs (per kWh) for operating the proxy gas turbine and coal-fired steam plants identified in the preceding table. The on-peak energy cost is taken as the operating cost of a combustion turbine; the mid-peak (morning peak) and off-peak marginal energy costs are taken as that of the coal-fired steam units identified above.

By way of illustration, the border price long-run marginal costs of energy at generation (before losses) for peak energy (summer) and off-peak energy (winter) are given as:

$$\textit{Summer Peak Energy} = \left(\frac{12000 Btu}{kWh} \times \frac{\$3.65}{GJ} + \frac{\$1.056 GJ}{MMBtu}\right) \times \frac{Zl13400}{\$} = 620\ Zl/kWh$$

[5] As a practical matter, due to operational constraints in the system, Summer mid-peak marginal energy cost falls between the operation costs of a small coal plant and a gas turbine (see Chapter 4). In the model, a "dummy" heat rate was assigned to simulate the marginal cost defined through a production cost simulation of the system in 1997.

EXHIBIT 7-2
MARGINAL ENERGY COSTS

| Assumptions for Marginal Energy Cost Calculations: | SUMMER SEASON 8/ PEAK-1 | PEAK-2 | MID-PK | OFF-PK | WINTER SEASON 8/ PEAK-1 | PEAK-2 | MID-PK | OFF-PK |
|---|---|---|---|---|---|---|---|---|
| Marginal Plant | C-TURB | | COAL | COAL | C-TURB | | COAL 9/ | COAL |
| Heat Rate (BTU/kWh) | 12000 | | 13289 | 9984 | 12000 | | 18700 | 9734 |
| Fuel Used | Gas | | Coal | Coal | Gas | | Coal | Coal |
| Fuel Cost (US$/unit) 7/ | 3.86 | | 2.12 | 2.12 | 3.86 | | 2.12 | 2.12 |
| Heat Content (MMBtu/unit) | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 |
| Variable O&M ($/MMBtu) | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| Utilization of Plant on Peak (%) | 100% | 0% | | | 100% | 0% | | |

MARGINAL ENERGY COST (tysZl/KWh): 1/

| | SUMMER SEASON 2/ PEAK | MID-PK | OFF-PK | WINTER SEASON 2/ PEAK | MID-PK | OFF-PK | ANNUAL AVERAGE 2/ PEAK | MID-PK | OFF-PK |
|---|---|---|---|---|---|---|---|---|---|
| GEN | 0.670 | 0.407 | 0.306 | 0.670 | 0.573 | 0.298 | 0.670 | 0.490 | 0.302 |
| (adjusted to local prices and for station losses) | | | | | | | | | |
| VHV | 0.682 | 0.415 | 0.310 | 0.682 | 0.584 | 0.303 | 0.682 | 0.499 | 0.306 |
| HV | 0.713 | 0.433 | 0.321 | 0.713 | 0.610 | 0.313 | 0.713 | 0.522 | 0.317 |
| MV | 0.736 | 0.448 | 0.329 | 0.736 | 0.630 | 0.321 | 0.736 | 0.539 | 0.325 |
| LV | 0.832 | 0.506 | 0.361 | 0.832 | 0.712 | 0.352 | 0.832 | 0.609 | 0.356 |

1/ Energy Costs derived directly from basic assumptions regarding marginal plant, heat rate, fuel cost, fuel heat content, and variable O&M.

$$\textit{Winter Off-Peak Energy} = \left(\frac{9{,}734 Btu}{kWh} \times \frac{\$2.01}{GJ} + \frac{\$1.056 GJ}{MMBtu}\right) \times \frac{Zl\ 13400}{\$} = 276.5\ Zl/kW$$

Subsequently, these estimates are further adjusted to local prices for our estimate of the LRMC of energy at generation by season and time of day,as shown in the lower panel of Exhibit 7-2.[6]

### Marginal Generation Capacity Cost

In contrast to the marginal energy cost calculation, there is no universally accepted method for estimating the LRMC for generation capacity. Whereas there is general agreement at a conceptual level, when it comes to estimation, a consensus is lacking. Several methods have been proposed. Three methods frequently mentioned are:

- peaker method
- next-plant method
- incremental revenue requirements method.

It is beyond the scope of this report to provide a detailed description of these methods, the subtleties involved, and their relative merits and disadvantages. Briefly, however, long-run marginal generational capacity cost is defined as the changes in total future costs associated with a 1 kW increase in peak demand, sustained indefinitely into the future. The methods noted above differ in what they *assume* to be hypothetical system response to the hypothetical increment in peak load.

The peaker method is rationalized on the basis that the least-cost means of securing capacity is a peaking unit, and the reason any other type of generation is built is to derive the energy savings. The annualized cost of such a unit -- adjusted for reserve margin and losses, and appropriately discounted to today from the year it is needed -- is the marginal cost of generation capacity. The following equation captures this calculation:

$$\textit{Marginal Generation Capacity Cost (Zl/coincidentKW/year)} = K \times \left(\frac{1+RM}{1-SL}\right)$$

[6] These marginal energy costs must also be adjusted for losses if the energy is not sold at the busbar.



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where,

K = annualized cost of peaking unit (Zl/kW/yr)
RM = planning reserve margin (%)
SL = station losses (%).

This cost (in constant prices) is subsequently discounted from the first year in the future when the reserve margin constraint (or the loss-of-load probability criterion) is binding, and adjusted upwards for incremental fixed O&M expenses, as well as any downstream losses up to the point of delivery. Finally, this cost can be allocated to different rating periods in the study (e.g., peak, mid-peak, and off-peak) using a number of different methods. A common allocation method is on the basis of the contribution of each rating period to the annual loss-of-load probability (LOLP).

Under the next-plant method, it is assumed that the 1 kW load increment (decrement) will be met by appropriately advancing forward (delaying) whichever power plant is planned to come on-line next. For example, if the next plant called for in the system plan is a baseload lignite unit planned for 2001,[7] then its annualized cost can be used to establish the LRMC, after assigning credit for any fuel savings as a result of having a more fuel-efficient plant.

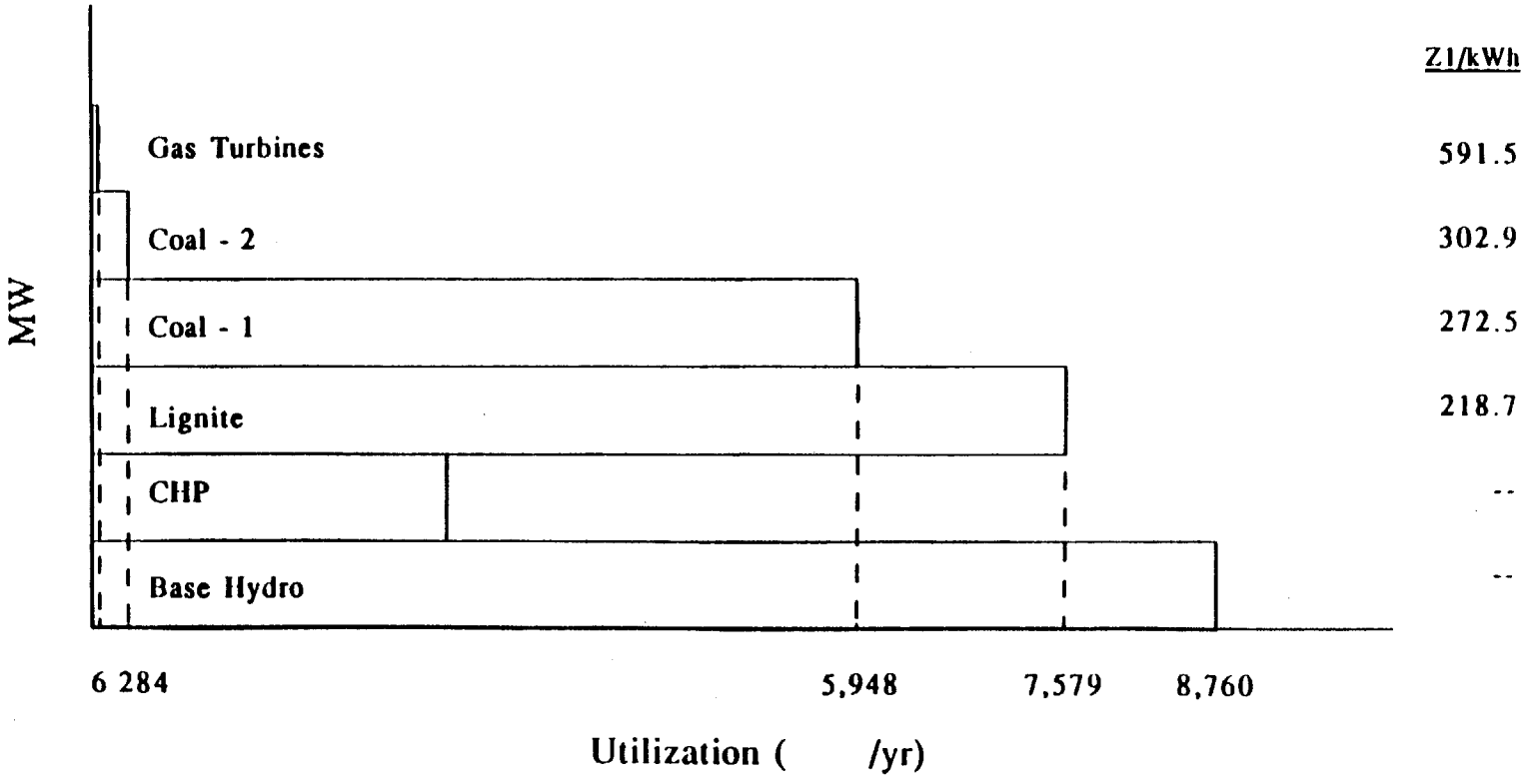
Exhibit 7-3 helps to illustrate the fuel savings adjustment that is required when using the next-plant method to estimate marginal generation capacity cost. The exhibit shows a schematic annual load duration curve with a merit order stacking of generating plants. If the "next plant" in the least-cost expansion program is a baseload lignite unit, then 1 kW of additional capacity from such a unit will have the effect of displacing generation of all more expensive units, i.e., units higher up in the stacking order. In the illustration in Exhibit 7-3, this is depicted as reducing 1 kW of "Coal-1" generation for 5,948 hours, 1 kW of "Coal-2" for 284 hours, and 1 kW of gas turbine generation for 6 hours. Thus, the annual fuel savings that should be credited against the annualized capital cost of the lignite plant are given by the calculation [5948 x (272.5 - 218.7) + 284 x (302.9 - 272.5) + 6 x (591.5 - 302.9)] Zl/kW/year. Therefore, the marginal generation capacity cost under the next-plant method is inferred as the annualized capital cost of the lignite plant (expressed in Zl/kW/year) less the fuel savings estimated as above.

In contrast to the two methods described above, the incremental revenue requirements method re-optimizes the entire expansion plan and estimates the incremental difference in the present value of two expenditure streams. Reoptimization of the expansion plan requires the

[7] Excluding combustion turbines (already reflected in the peaker method) and pumped hydro (whose benefits exceed pure capacity), such a lignite plant is the "next plant" in the least-cost development plan.

Exhibit 7-3

# Marginal Generation Capacity Costs Using "Next Plant" Method




Marginal capacity cost = Annualized cost of lignite plant minus fuel savings

Fuel savings = [5948 x (272.5 - 218.7)] + [284 x (302.9 - 272.5)] + [6 x (59.5 - 302.9)] (Z1/kWh)

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use of sophisticated optimization system expansion planning models.[8] We have employed a variation of this methodology to calculate the "avoided cost" of the CHP generation supplied to the system (see Chapter 4).

Implementing the incremental revenue requirements method requires a substantial commitment of resources. More fundamentally, however, the incremental revenue requirements method is characterized by a conceptual flaw. Estimates of "marginal cost" developed by this method are weighted averages of capacity costs of a diverse mix of marginal as well as inframarginal plant types: peaking, intermediate, and baseload. Such a basis is contrary to the notion of marginal capacity cost, i.e., the cost of meeting a marginal increment of demand on-peak.

As a practical matter, the three methods should yield similar estimates of LRMC under conditions where the utility's generating mix is not substantially different from the least-cost mix and the reserve margin is just adequate. Under such conditions, the "next unit" for capacity purposes will indeed be a peaker and the system reoptimization method should also elect to advance the peaker.

In practice, the peaker method is by far the most frequently used method, providing a close approximation of the pure value of an increment of capacity. Use of the incremental revenue requirements method is less frequent but is probably the best when a firm expansion plan is available. Because the method provides the most complex system response to meet an increment of new load, it is more commonly utilized in the context of estimating "avoided costs" for calculating payments for power purchases. The "next plant" method, while providing only an imperfect measure of the system response to a capacity addition, has been applied in some regulatory environments as an alternative to the peaker method, particularly when new peeking capacity is not part of the system expansion plan. This method is less reliable than the others two.

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[8] For example, the International Atomic Energy Agency's WASP model for optimal generation expansion planning, or the GPT model described in Chapter 4. Specifically, three model runs are required as follows. Run 1 corresponds to optimizing the system generation expansion plan to the baseload forecast. Model Run 2 reoptimizes the system expansion plan with the peak load forecast used in Run 1 incremented by the equivalent of one year's load growth. Finally, Run 3 is a production simulation (e.g., WASP in a "pre-specified pathway" mode) to estimate the fuel costs associated with the load forecast used in Run 1, but unit staging determined in Run 2. Thus, LRMC for generation capacity can be estimated by calculating the following quantity and levelizing it:

$$[(CR_1 - CR_2) + (FC_3 - FC_1)]/DMW$$

where $CR_i$ is the capital investment associated with model run i (i = 1, 2, 3), $FC_i$ is the fuel (production) cost associated with the expansion plan model run i, and DMW is the megawatt incremental difference in peak load between Runs 1 and 2.

Based upon our review of the expansion plan, we believe that the peaker method is appropriate for estimating the marginal cost of generation capacity. However, for the purposes of comparison, we have also estimated generation capacity cost using the next-plant method. For this purpose, the first baseload plant added to the system in the least-cost expansion plan (a lignite plant in the year 2001) provides the only reasonable proxy. As noted above, the results of this method are not reliable and are only provided as an illustration.

Exhibit 7-4 depicts key input assumptions and results for the LRMC model for the marginal generation capacity cost calculation. At an exchange rate of Zl 13,400 to US $1.00 and a standard conversion factor of 1.0, the border prices discounted back from the year the capacity is required, are 3,073 TysZl/kW for a peaker plant[9] and 8,551 TysZl/kW[10] less associated fuel savings of 330 TysZl/kW/year for the lignite plant. These costs are subsequently annualized over the respective plant lifetimes, adjusted to local prices and for reserve margin, station losses, and incremental O&M expense.

### Marginal Network Capacity Cost

The transmission and distribution (T&D) network's capacity is designed to accommodate peak demand power flows from generation to end users. Further, in a growing system, such network capacity is sized and sequenced recognizing future growth potential as well. Generally, all investment costs for T&D are allocated to incremental capacity since the designs of these facilities are determined principally by the peak kilowatts that they carry rather than by kilowatt-hours. The most frequently used approach for estimating marginal T&D capacity cost, and the one which we have also used, is the long-run average incremental cost (LRAIC) method.

The LRAIC represents the present value of all T&D investments over the planning horizon divided by the present value of the corresponding annual increments in peak load. This value, expressed in Zl per incremental kW, is then annuitized over the life of the facilities, resulting in the annuitized capacity cost, expressed in Zl/kW/year.

Separate LRAICs must be estimated for each major voltage level of the grid -- very high voltage (VHV), high voltage (HV), medium voltage (MV), and low voltage (LV) -- as depicted schematically in Exhibit 7-5.

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[9] i.e., $(4033 + 1083 \times 1.0) \times (1/(1.12)^5)$.

[10] i.e., $(3557 + 20155 \times 1.0) \times (1/(1.12)^9)$.

EXHIBIT 7-4
GENERATION CAPACITY COST - PEAKER AND "NEXT PLANT" METHODS (tysZl/KW)

| ASSUMPTIONS | PEAKER METHOD | "NEXT PLANT" |
|---|---|---|
| Marginal Plant | C-TURB | LIGNITE |
| Life (years) | 20 | 30 |
| O&M and A&G (% of capital cost) | 4.50% | 1.87% |
| Year Generation Required | 1997 | 2001 |
| Capital Cost: | | |
| Foreign (tysZl/KW) | 4332.7 | 3556.8 |
| Local Materials | 1083.2 | 20155.4 |
| Local Labor 4/ | 0.0 | 0.0 |
| CAPACITY COST (discounted to study year) | | |
| Market Price | 3073.09 | 8550.86 |
| Border Price | 3073.09 | 8550.86 |

PSE/POLISH POWER GRID
RANKING OF GENERATING PLANTS BY VARIABLE COST - 1997

| GENERATING PLANT GROUPS | TYPE | MEGA-WATTS (MW) 1/ | ANNUAL USE Hrs/Yr | VARIABLE COST $/KWh | VARIABLE COST tysZl/KWh | HEAT RATE Btu/KWh | FUEL COST $/MMBtu | VAR. O&M (% FUEL COST) |
|---|---|---|---|---|---|---|---|---|
| BASE HYDRO | HYDRO | 80 | 8760 | - | - | - | - | - |
| COMB. HEAT AND POWER 2/ | CHP | 5901 | 2597 | - | - | - | - | - |
| LIGNITE-FIRED | LIGNITE | 8791 | 7579 | 0.0163 | 0.2187 | 10118 | 1.61 | 0.0% |
| COAL-FIRED STEAM 1 | COAL-1 | 11652 | 5948 | 0.0203 | 0.2725 | 9582 | 2.12 | 0.0% |
| COAL-FIRED STEAM 2 | COAL-2 | 2292 | 284 | 0.0226 | 0.3029 | 10652 | 2.12 | 0.0% |
| COMBUSTION TURBINES | C-TURB | 240 | 6 | 0.0441 | 0.5915 | 12000 | 3.68 | 0.0% |
| PUMPED STORAGE | P-STOR | 1890 | 1420 | - | - | - | - | - |

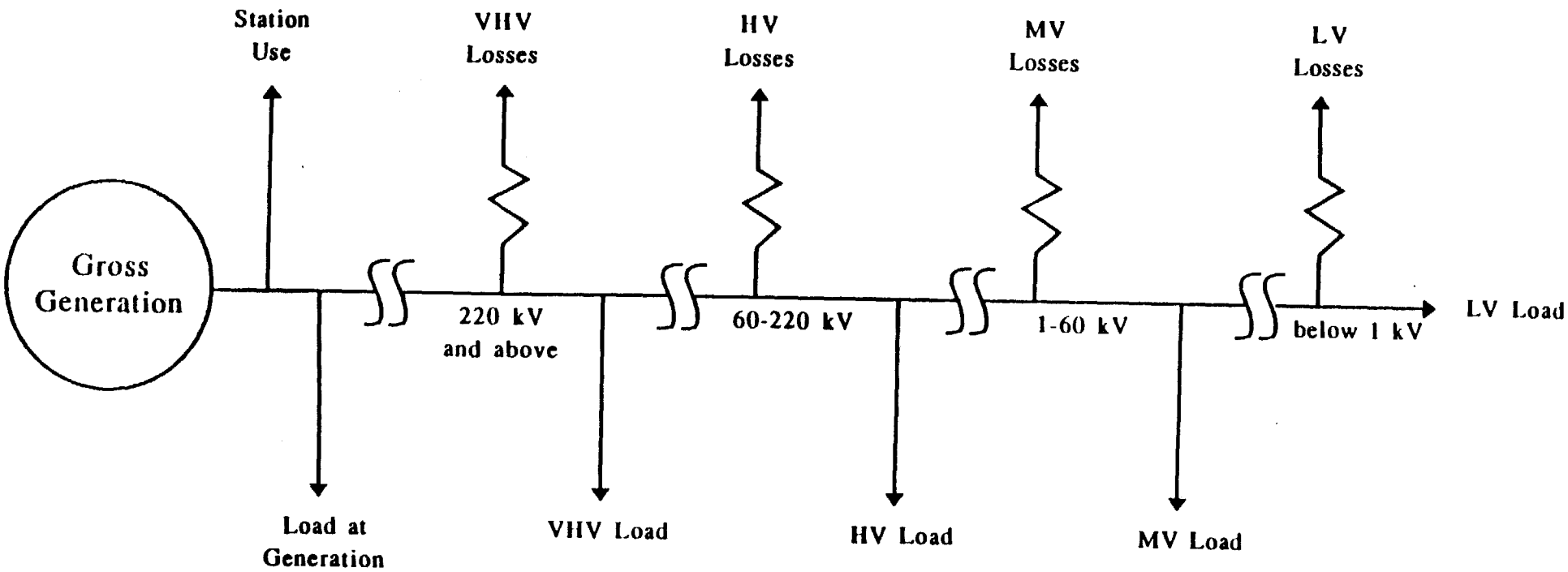
1/ Installed capacity.
2/ Megawatt capacity includes 1290 MW autogeneration.
3/ Based on PSE practice, all O&M is treated as a fixed cost

ASSOCIATED FUEL SAVINGS - "NEXT PLANT" METHOD

| ---UNIT TYPE--- NEW | DISPL | COST (tysZl/KWh) NEW | DISPL | HRS/YR | SAVINGS (tysZl/KW) |
|---|---|---|---|---|---|
| LIGNITE | COAL-1 | 0.2187 | 0.2725 | 5948 | 320.01 |
| COAL-1 | COAL-2 | 0.2725 | 0.3029 | 284 | 8.64 |
| COAL-2 | C-TURB | 0.3029 | 0.5915 | 6 | 1.73 |
| TOTAL FUEL SAVINGS (tysZl/KW/Yr) | | | | | 330.38 |

Exhibit 7-5

# Schematic Representation of the Polish Power Grid



The schematic representation is a simplification adopted to facilitate more coherent modeling. Of course, electricity is generated at many points in the network, and more detailed power flows can be used to determine specific point to point tariff structures.

To estimate separate LRAICs for each voltage, capital expenditures, lines, and loads must be estimated for each voltage level. Exhibit 7-6 displays the incremental investments by voltage. These were derived from the most recent investment program of PPGC, and from a planning study of distribution network investment needs prepared by the Institute of Power Engineering.[11] The details of these programs are presented in Appendix 7.1.

Forecasts of energy consumption by voltage level are shown in Exhibit 7-7. These allocations were derived from PPGC's forecast of sales and peak demand for the national grid (see Chapter 2). System peak loads are derived from total sales by applying a system load factor because peak load forecasts are not available by voltage.

The model also requires estimates of peak and average loss coefficients at each voltage level as a percent of incoming load. Based upon discussions with PPGC's transmission planning staff, average network losses in 1991 were allocated by voltage level as 1.5 percent for VHV, 3.4 percent for HV, 1.8 percent for MV, and 4.3 percent for LV (for a total of 11.1 percent). For subsequent years, these values were scaled to match PPGC's total network loss forecast.

Peak loss calculations in the model are determined according to the following empirical formula, which has been developed based upon experience in many countries:

$$\textit{Peak Losses} = \frac{\textit{Average Losses}}{.3 + (.7 \times \textit{Load Factor})}$$

Estimates of average and peak loss factors by voltage level are shown in Exhibit 7-8.

Estimates of incoming peak load, losses, and consumption in MW at each voltage level as calculated by the model are shown in Exhibit 7-9. The exhibit displays the predicted coincident power balance under each voltage for the years 1992 through 2001. To illustrate, in the year 1993, the gross peak level of 22,224 MW, after adjusting for 1,596 MW of station use (based upon application of the peak station use factors in Exhibit 7-8), and after

[11] A consolidated investment program by voltage level for the distribution companies is not available. Since the best available investment program for the distribution companies is a "requirements" plan, there is some concern that it may *overstate* a realistic investment program. The impact of a lower investment program on estimated LRMCs is considered in the sensitivity analysis of Section 7.3.

EXHIBIT 7-6
NETWORK CAPACITY COSTS (tysZI MILLION)

| YEAR | VHV COSTS | | | | HV COSTS | | | |
|---|---|---|---|---|---|---|---|---|
| ENDING | TOTAL | FOREIGN | LOC Mat. | LOC Labor | TOTAL | FOREIGN | LOC Mat. | LOC Labor |
| 1992 | 331.00 | 264.80 | 66.20 | 0.00 | 430.15 | 141.96 | 288.19 | 0.00 |
| 1993 | 158.00 | 126.40 | 31.60 | 0.00 | 696.64 | 243.18 | 453.46 | 0.00 |
| 1994 | 1079.00 | 750.70 | 328.30 | 0.00 | 752.02 | 259.45 | 492.57 | 0.00 |
| 1995 | 1694.00 | 1241.05 | 452.95 | 0.00 | 844.50 | 282.20 | 562.30 | 0.00 |
| 1996 | 1610.00 | 1183.00 | 427.00 | 0.00 | 790.79 | 254.66 | 536.12 | 0.00 |
| 1997 | 206.00 | 164.80 | 41.20 | 0.00 | 633.89 | 150.01 | 483.88 | 0.00 |
| 1998 | 200.00 | 160.00 | 40.00 | 0.00 | 586.38 | 114.24 | 472.14 | 0.00 |
| 1999 | 1161.00 | 823.80 | 337.20 | 0.00 | 684.75 | 175.96 | 508.80 | 0.00 |
| 2000 | 1243.00 | 888.20 | 354.80 | 0.00 | 794.75 | 247.46 | 547.30 | 0.00 |
| 2001 | 1160.00 | 823.00 | 337.00 | 0.00 | 482.01 | 164.26 | 317.75 | 0.00 |

| YEAR | MV COSTS | | | | LV COSTS | | | |
|---|---|---|---|---|---|---|---|---|
| ENDING | TOTAL | FOREIGN | LOC Mat. | LOC Labor | TOTAL | FOREIGN | LOC Mat. | LOC Labor |
| 1992 | 1354.40 | 181.72 | 1172.68 | 0.00 | 1497.32 | 200.90 | 1296.42 | 0.00 |
| 1993 | 1385.93 | 185.95 | 1199.98 | 0.00 | 1519.00 | 203.81 | 1315.19 | 0.00 |
| 1994 | 1374.08 | 184.36 | 1189.72 | 0.00 | 1529.70 | 205.24 | 1324.46 | 0.00 |
| 1995 | 1452.66 | 194.91 | 1257.75 | 0.00 | 1575.09 | 211.33 | 1363.75 | 0.00 |
| 1996 | 1738.85 | 233.31 | 1505.55 | 0.00 | 1541.22 | 206.79 | 1334.43 | 0.00 |
| 1997 | 1835.04 | 246.21 | 1588.83 | 0.00 | 1565.58 | 210.06 | 1355.52 | 0.00 |
| 1998 | 1835.04 | 246.21 | 1588.83 | 0.00 | 1585.09 | 212.68 | 1372.41 | 0.00 |
| 1999 | 1868.57 | 250.71 | 1617.86 | 0.00 | 1604.59 | 215.29 | 1389.30 | 0.00 |
| 2000 | 1897.70 | 254.62 | 1643.08 | 0.00 | 1628.95 | 218.56 | 1410.39 | 0.00 |
| 2001 | 1897.70 | 254.62 | 1643.08 | 0.00 | 1628.95 | 218.56 | 1410.39 | 0.00 |

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EXHIBIT 7 7
GRID SALES AND LOSS FORECAST

| YEAR ENDING | PEAK (MW) | GROSS GEN (GWh) | LOAD FACTOR | CONSUMPTION BY VOLTAGE LEVEL (GWh) 1,2 | | | | | | AVERAGE LOSSES BY VOLTAGE LEVEL (GWh) 3/ | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | TOTAL | GEN | VHV | HV | MV | LV | STN USE | VHV | HV | MV | LV | TOTAL |
| 1992 | 22024 | 125100 | 64 8 | 102625 | 4352 | 3200 | 28229 | 24943 | 41901 | 8986 | 1840 | 4179 | 2241 | 5229 | 22475 |
| 1993 | 22224 | 127100 | 65 3 | 105175 | 4400 | 3200 | 28158 | 25471 | 43945 | 9129 | 1745 | 3965 | 2126 | 4960 | 21925 |
| 1994 | 22526 | 129700 | 65 7 | 108191 | 4450 | 3300 | 28146 | 26102 | 46193 | 9315 | 1663 | 3778 | 2026 | 4727 | 21509 |
| 1995 | 22978 | 133200 | 66 2 | 112300 | 4500 | 3300 | 28410 | 27051 | 49040 | 9565 | 1546 | 3512 | 1883 | 4394 | 20900 |
| 1996 | 22989 | 135300 | 67 2 | 113658 | 4539 | 1900 | 29049 | 27665 | 50506 | 9736 | 1624 | 3689 | 1978 | 4615 | 21642 |
| 1997 | 23570 | 138900 | 67 3 | 116633 | 4578 | 1900 | 29742 | 28329 | 52084 | 10016 | 1671 | 3796 | 2035 | 4749 | 22267 |
| 1998 | 24077 | 142600 | 67 6 | 119669 | 4618 | 1900 | 30451 | 29010 | 53711 | 10304 | 1720 | 3906 | 2094 | 4887 | 22911 |
| 1999 | 24660 | 146300 | 67 7 | 122742 | 4659 | 1900 | 31153 | 29684 | 55347 | 10593 | 1768 | 4017 | 2154 | 5025 | 23557 |
| 2000 | 25173 | 148600 | 67 4 | 125000 | 4700 | 1900 | 31637 | 30151 | 56613 | 10781 | 1749 | 3972 | 2129 | 4969 | 23600 |
| 2001 | 25279 | 150400 | 67 9 | 126187 | 4719 | 0 | 32373 | 30906 | 58188 | 10900 | 1616 | 4125 | 2212 | 5160 | 24213 |

1/ Consumption at generation includes pumping in hydro plants plus heat generation auxiliary use minus self - producer supply to grid. consumption at VHV includes net exports
2/ Flows are subsequently converted in the model as consumption demand by applying the system load factor
3/ Average network losses by voltage level have been estimated based on the following allocation of total losses at a percent of net generation

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EXHIBIT 7 8
AVERAGE AND PEAK LOSS FACTORS (FRACTION OF INCOMING)

| YEAR | STATION USE - | | VHV | | HV | | MV | | LV | |
|---|---|---|---|---|---|---|---|---|---|---|
| ENDING | AVERAGE | PEAK | AVERAGE | PEAK | AVERAGE | PEAK | AVERAGE | PEAK | AVERAGE | PEAK |
| 1992 | 0 072 | 0 072 | 0 016 | 0 022 | 0 039 | 0 052 | 0 030 | 0 040 | 0 111 | 0 147 |
| 1993 | 0 072 | 0 072 | 0 015 | 0 020 | 0 037 | 0 048 | 0 028 | 0.037 | 0 101 | 0 134 |
| 1994 | 0 072 | 0 072 | 0 014 | 0 019 | 0 034 | 0 045 | 0 026 | 0 034 | 0 093 | 0 122 |
| 1995 | 0 072 | 0.072 | 0.013 | 0 017 | 0 031 | 0 040 | 0 023 | 0 030 | 0 082 | 0 108 |
| 1996 | 0 072 | 0 072 | 0 013 | 0 017 | 0 031 | 0 041 | 0.023 | 0 030 | 0 084 | 0 109 |
| 1997 | 0 072 | 0.072 | 0.013 | 0 017 | 0 031 | 0 041 | 0 023 | 0 030 | 0 084 | 0 108 |
| 1998 | 0 072 | 0 072 | 0 013 | 0 017 | 0 031 | 0 041 | 0 023 | 0 030 | 0 083 | 0 108 |
| 1999 | 0 072 | 0.072 | 0 013 | 0 017 | 0 032 | 0 041 | 0 023 | 0 030 | 0 083 | 0 108 |
| 2000 | 0 073 | 0.073 | 0.013 | 0 017 | 0 031 | 0 040 | 0 023 | 0 029 | 0 081 | 0 105 |
| 2001 | 0 072 | 0 072 | 0 013 | 0 017 | 0 031 | 0 040 | 0 023 | 0.030 | 0 081 | 0 105 |
| Average | 0.072 | 0.072 | 0.014 | 0.018 | 0.033 | 0 043 | 0.025 | 0.032 | 0 088 | 0.115 |

EXHIBIT 7 - 9
DEMAND AND LOSS FORECAST AT TIME OF SYSTEM PEAK (MW)

| YEAR | PEAK | STATION | GEN | VHV | | | HV | | | MV | | | LV | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ENDING | | USE | CONSUM | LOSS | PEAK | CONSUM | LOSS | PEAK | CONSUM | LOSS | PEAK | CONSUM | LOSS | PEAK |
| 1992 | 22024 | 1582 0 | 766 2 | 429 7 | 19246 1 | 563 4 | 970 5 | 17712 3 | 4969 8 | 509 7 | 12232 8 | 4391 2 | 1153 9 | 6687 7 |
| 1993 | 22224 | 1596 2 | 769 4 | 403 2 | 19454 9 | 559 5 | 911.1 | 17984 3 | 4923 6 | 479 4 | 12581 3 | 4453 7 | 1089 0 | 7038 7 |
| 1994 | 22528 | 1617 9 | 772 9 | 380.1 | 19757 2 | 573.2 | 859.4 | 18324 6 | 4888 8 | 453 0 | 12982 8 | 4533 8 | 1031 9 | 7417 1 |
| 1995 | 22978 | 1650 0 | 776 3 | 349 5 | 20201 9 | 569 3 | 790.5 | 18842 2 | 4900 8 | 417 6 | 13523 8 | 4666 4 | 954 3 | 7903 1 |
| 1996 | 22989 | 1654 2 | 771 2 | 358 2 | 20205 1 | 322 8 | 810.4 | 19071 9 | 4935 7 | 428 2 | 13708 0 | 4700 5 | 979 1 | 8028 5 |
| 1997 | 23570 | 1699 6 | 776 9 | 367 9 | 20726 2 | 322 4 | 832 2 | 19571 6 | 5047 0 | 439 8 | 14084 8 | 4807 3 | 1005 6 | 8271 9 |
| 1998 | 24077 | 1739 7 | 779 7 | 375 5 | 21182 4 | 320 8 | 849 5 | 20012 1 | 5141 5 | 449 0 | 14421 6 | 4898 1 | 1027 1 | 8496 4 |
| 1999 | 24660 | 1785 5 | 785 2 | 385 1 | 21703 9 | 320 3 | 871 2 | 20512 5 | 5251 0 | 460 5 | 14801 0 | 5003 4 | 1053 6 | 8743 9 |
| 2000 | 25173 | 1826 4 | 796 2 | 383 8 | 22166 5 | 321 9 | 868 4 | 20976 3 | 5359 2 | 459 1 | 15157 9 | 5107 5 | 1050 8 | 8999 5 |
| 2001 | 25279 | 1832.1 | 793.2 | 393 6 | 22259 7 | 0.0 | 890.6 | 21369.1 | 5441 2 | 470 9 | 15457 0 | 5194 5 | 1078 1 | 9184 4 |

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adjusting for generation consumption (heat generation auxiliary use and hydro pumping) of 769 MW and VHV network losses of 403 MW, results in a VHV peak of 19,455 MW. Of this amount, 560 MW of load is supplied at this voltage (net exports), with the remaining power transmitted to the HV network. The HV peak is estimated to be 17,984 MW, after adjusting for losses of 911 MW. In this manner, the power balance is sequentially derived to arrive at an estimated LV network peak of 7,038 MW.

Exhibit 7-10 shows the calculation of separate LRAICs for the four voltage levels. Incremental peak loads are calculated from Exhibit 7-9, whereas incremental expenditures are calculated from Exhibit 7-6. These costs are subsequently annualized over their respective lifetimes, and then adjusted to local prices and for incremental O&M expense as shown in Exhibit 7-11.

### Results

Estimates of marginal generation capacity cost and network capacity cost (expressed as Zl/coincident kW) are summarized in Exhibit 7-11. In the model and the foregoing discussion, both capacity and energy costs are calculated at border prices. In order to estimate the long-run marginal cost as seen by the customer, these border prices must be re-expressed in terms of local prices (i.e., divided by the SCF). The capital cost of generation capacity must also be adjusted to account for the desired reserve margin and station losses at peak. The "summary of capacity costs" in Exhibit 7-11 makes these adjustments, annualizes investment costs, adds in an appropriate factor for annual O&M (including administrative and general expenses), and estimates a capacity cost per month for generation and network at each voltage level. To illustrate, the marginal generation capacity cost (peaker method) is 59.26 TysZl/coincident kW/month.

Similarly, Exhibit 7-11 derives the marginal cost of network capacity (Zl/coincident kW/month) at each voltage level. These costs range from 27.70 TysZl/kW/month at HV to 74.65 TysZl/kW/month at LV.

Exhibit 7-12 presents estimates of strict long-run marginal costs by voltage level. To illustrate, marginal capacity costs (generation plus network) using the peaker method range from 93.21 TysZl/coincident kW/month for load served at VHV to 285.69 TysZl/coincident kW/month for LV load. Similarly, average annual marginal energy costs at LV are 428 Zl/kWh during the peak hours and 356 Zl/kWh during off-peak hours. These costs are progressively lower (reflecting reduced losses) as service is taken at higher voltages.

In order to apply the strict marginal cost estimates discussed above to each tariff class, additional factors must be considered. These are: the coincidence of peak for each class in relation to the system peak, the load factor for each type of customer, and the split of total

EXHIBIT 7 10
AVERAGE INCREMENTAL NETWORK CAPACITY COSTS BY VOLTAGE LEVEL (tysZI MILLION)

VHV NETWORK

| YEAR ENDING | PEAK MW TOTAL | PEAK MW DISCOUNTED | INVESTMENT COST MARKET | INVESTMENT COST BORDER | INVESTMENT COST DISCOUNTED |
|---|---|---|---|---|---|
| 1992 | 0 00 | 0 00 | 331 00 | 331 00 | 331 00 |
| 1993 | 208 79 | 186 42 | 158 00 | 158 00 | 141 07 |
| 1994 | 302 26 | 240.96 | 1079 00 | 1079 00 | 860 17 |
| 1995 | 444 75 | 316 57 | 1694 00 | 1694 00 | 1205 76 |
| 1996 | 3 18 | 2 02 | 1610 00 | 1610 00 | 1023.18 |
| 1997 | 521 05 | 295.66 | 206 00 | 206 00 | 116 89 |
| 1998 | 456 24 | 231 15 | 200 00 | 200.00 | 101 33 |
| 1999 | 521 50 | 235.90 | 1161 00 | 1161 00 | 525.18 |
| 2000 | 462 58 | 186 83 | 1243 00 | 1243 00 | 502 03 |
| 2001 | 93 22 | 33 82 | 1160 00 | 1160 00 | 418 31 |
| Lagged Total | | 1542 70 (1994 - 2001) | | | 4304 58 (1992 99) |

AVERAGE INCREMENTAL VHV CAPACITY COST/KW - 2790 29

HV NETWORK

| YEAR ENDING | PEAK MW TOTAL | PEAK MW DISCOUNTED | INVESTMENT COST MARKET | INVESTMENT COST BORDER | INVESTMENT COST DISCOUNTED |
|---|---|---|---|---|---|
| 1992 | 0 00 | 0 00 | 430 15 | 430 15 | 430 15 |
| 1993 | 272 02 | 242 88 | 696 64 | 696 64 | 622 00 |
| 1994 | 340 32 | 271 30 | 752 02 | 752 02 | 599 51 |
| 1995 | 517 58 | 368 40 | 844 50 | 844 50 | 601 10 |
| 1996 | 229 73 | 146 00 | 790 79 | 790 79 | 502 56 |
| 1997 | 499 64 | 283 51 | 633 89 | 633 89 | 359 69 |
| 1998 | 440 53 | 223 19 | 586 38 | 586 38 | 297 08 |
| 1999 | 500 38 | 226 35 | 684 75 | 684 75 | 309 75 |
| 2000 | 463 79 | 187 32 | 794 75 | 794 75 | 320 99 |
| 2001 | 392 89 | 141 68 | 482 01 | 482 01 | 173 82 |
| Lagged Total | | 1847 73 (1994 2001) | | | 3721 82 (1992 99) |

AVERAGE INCREMENTAL HV CAPACITY COST/KW - 2014 26

MV NETWORK

| YEAR ENDING | PEAK MW TOTAL | PEAK MW DISCOUNTED | INVESTMENT COST MARKET | INVESTMENT COST BORDER | INVESTMENT COST DISCOUNTED |
|---|---|---|---|---|---|
| 1992 | 0 00 | 0 00 | 1354 40 | 1354 40 | 1354 40 |
| 1993 | 348 51 | 311 17 | 1385 93 | 1385 93 | 1237.44 |
| 1994 | 401 45 | 320 03 | 1374 08 | 1374 08 | 1095.41 |
| 1995 | 541 05 | 385 11 | 1452 66 | 1452 66 | 1033 97 |
| 1996 | 184 19 | 117 05 | 1738 85 | 1738 85 | 1105 07 |
| 1997 | 376 79 | 213 80 | 1835 04 | 1835 04 | 1041 25 |
| 1998 | 336 83 | 170 65 | 1835 04 | 1835 04 | 929 69 |
| 1999 | 379 35 | 171 60 | 1868 57 | 1868 57 | 845 25 |
| 2000 | 356 93 | 144 16 | 1897 70 | 1897 70 | 766 45 |
| 2001 | 299.13 | 107.87 | 1897 70 | 1897 70 | 684 33 |
| Lagged Total | | 1941.44 (1993 - 2001) | | | 9408 93 (1992 - 00) |

AVERAGE INCREMENTAL MV CAPACITY COST/KW = 4846.36

LV NETWORK

| YEAR ENDING | PEAK MW TOTAL | PEAK MW DISCOUNTED | INVESTMENT COST MARKET | INVESTMENT COST BORDER | INVESTMENT COST DISCOUNTED |
|---|---|---|---|---|---|
| 1992 | 0 00 | 0 00 | 1497 32 | 1497 32 | 1497 32 |
| 1993 | 351 02 | 313 41 | 1519 00 | 1519 00 | 1356 25 |
| 1994 | 378 38 | 301 64 | 1529 70 | 1529 70 | 1219 47 |
| 1995 | 486 05 | 345 96 | 1575 09 | 1575 09 | 1121 12 |
| 1996 | 125 35 | 79 66 | 1541 22 | 1541 22 | 979 47 |
| 1997 | 243 39 | 138 10 | 1565 58 | 1565 58 | 888 35 |
| 1998 | 224 48 | 113 73 | 1585 09 | 1585 09 | 803 05 |
| 1999 | 247 59 | 112 00 | 1604 59 | 1604 59 | 725 84 |
| 2000 | 255 59 | 103 23 | 1628 95 | 1628 95 | 657 91 |
| 2001 | 184 88 | 66 67 | 1628 95 | 1628 95 | 587 42 |
| Lagged Total | | 1574 41 (1993 2001) | | | 9248 77 (1992 00) |

AVERAGE INCREMENTAL LV CAPACITY COST/KW = 5874 43

EXHIBIT 7 - 11
SUMMARY OF CAPACITY COSTS

| GENERATION: | PEAKER METHOD | "NEXT PLANT" |
|---|---|---|
| CAPITAL COST (tysZl/KW) | 3974.27 | 11058.38 |
| (adjusted to local prices and for reserve margin and station losses at peak) | | |
| CAPITAL COST PER YEAR (tysZl/KW/Yr) | 532.07 | 1372.83 |
| ASSOCIATED FUEL SAVINGS (tysZl/KW/Yr) | – | 356.06 |
| (adjusted to local prices and for station losses) | | |
| CAPITAL COST NET OF FUEL SAVINGS (tysZl/KW/Yr) | 532.07 | 1016.77 |
| O&M COST PER YEAR (tysZl/KW/Yr) | 179.04 | 206.36 |
| TOTAL CAPITAL COST PER YEAR (tysZl/KW/Yr) | 711.11 | 1223.13 |
| CAPACITY COST PER MONTH | 59.26 | 101.93 |

| TRANSMISSION & DISTRIBUTION: | VHV | HV | MV | LV |
|---|---|---|---|---|
| CAPITAL COST (tysZl/KW) | 2790.29 | 2014.26 | 4846.36 | 5874.43 |
| (adjusted to local prices) | | | | |
| CAPITAL COST PER YEAR (tysZl/KW/Yr) | 338.47 | 244.34 | 617.91 | 748.99 |
| O&M COST PER YEAR (tysZl/KW/Yr) | 55.81 | 40.29 | 121.16 | 146.86 |
| TOTAL CAPITAL COST PER YEAR (tysZl/KW/Yr) | 394.28 | 284.62 | 739.07 | 895.85 |
| CAPACITY COST PER MONTH | 32.86 | 23.72 | 61.59 | 74.65 |

EXHIBIT 7 12
STRICT LONG RUN MARGINAL COST BASED TARIFF BY VOLTAGE LEVEL

MARGINAL CAPACITY COST (tysZl/COINCIDENT KW/MONTH)

| | GENERATION | | TRANSMISSION & DISTRIBUTION | | | | | TOTAL MARGINAL CAPACITY COST | |
|---|---|---|---|---|---|---|---|---|---|
| | PEAKER METHOD | "NEXT PLANT" | VHV | HV | MV | LV | TOTAL | PEAKER METHOD | "NEXT PLANT" |
| VHV | 60.36 | 103 82 | 32 86 | | | | 32 86 | 93 21 | 136.68 |
| HV | 63.06 | 108 46 | 34 33 | 23 72 | | | 58 04 | 121 10 | 166 50 |
| MV | 65 14 | 112 05 | 35 46 | 24.50 | 61 59 | | 121 55 | 186 70 | 233 60 |
| LV | 73.63 | 126 65 | 40 08 | 27.70 | 69 62 | 74 65 | 212 05 | 285 69 | 338 70 |

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energy between peak and off-peak. Applying the coincidence factors results in an estimate of total marginal capacity cost per month for each customer class.[12] These results are shown for PPGC's sales to distribution companies in Exhibit 7-13, and for distribution company final sales in Exhibit 7-14. In these exhibits, marginal energy cost is a weighted average of peak, mid-peak and off-peak costs. The class load factors are used to express capacity costs in terms of kWh.[13] The final line of each exhibit derives average system-wide strict LRMC estimates for PPGC and the consolidated distribution companies, respectively.

The strict LRMC values by tariff class shown in Exhibits 7-13 and 7-14 establish an economic benchmark for the purpose of evaluating the extent of distortions in the present tariffs. In the case of PPGC, the average[14] LRMC is 708.5 Zl/kWh in comparison with an estimated current average tariff yield (mid-1992 prices) of 339.8 Zl/kWh. For the distribution companies, the average LRMC is 987.9 Zl/kWh in comparison with an average tariff yield of 542.1 Zl/kWh.

Strict LRMC is a pure economic cost and as such does not represent what must be collected from electricity customers. Rather, tariffs must collect the financial revenue requirement (see Chapter 8), which is generally less than the strict long-run marginal cost.

## 7.3 SENSITIVITY ANALYSIS

It is useful to test the sensitivity of results to key input variables. This exercise helps to identify those assumptions with a significant impact on final LRMC calculations. We have analyzed the sensitivity of PPGC and distribution company average LRMC tariff to changes in the following variables:

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[12] In arriving at these assumptions, the study team members first reviewed and analyzed the load research data derived from surveys conducted by the Institute of Power Engineering (JEN/Katovica) and consolidated tariff class billing data compiled by PPGC for the past two years. We identified class load factors and coincidence factors from seasonal hourly load shapes estimated for each tariff class. Further, the billing records provided an independent estimate of class load factors. Where available data were insufficient, the assumptions made are also conditioned upon the team members' experience and judgment. In the absence of comprehensive national load research data, our estimates of coincidence factors are intentionally conservative; underestimation of coincidence factors would translate directly into undercollection of revenues for customers not metered on a coincident demand basis.

[13] To avoid unnecessary confusion, the printed table shows strict LRMCs for the peaker method. For comparative purposes, parallel results for the "next-plant" method appear in the model spreadsheet to the right of these printed data. A complete printout of the LRMC model results is contained in Appendix 5.2.

[14] Weighted by billed sales by tariff class recorded for the first half of 1992.

Exhibit 7 13
STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS – BULK

| TARIFF CLASS | SERVICE VOLTAGE | COINCI-DENCE | LOAD FACTOR | ENERGY SHARES PEAK | MID-PEAK | TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW | ENERGY tysZl/KWh | TOTAL tysZl/KWh | DEMAND CHARGE SHARE | H1/1992 SALES GWh | CURRENT YIELD tysZl/KWh |
|---|---|---|---|---|---|---|---|---|---|---|---|
| DISTRIBUTION COS. | HV | 1.00 | 0.65 | 0.20 | 0.28 | 121.10 | 0.4533 | 0.7085 | 36% | 50434 | 0.3398 |
| BULK SYSTEM AVERAGE | | | | 0.20 | 0.28 | 121.10 | 0.4533 | 0.7085 | | 50434 | 0.3398 |
| Equivalent tysZl/KWh | | | | | | 0.2552 | 0.4533 | 0.7085 | | | |
| % of System Average | | | | | | 36% | 64% | 100% | | | |

Exhibit 7 - 14
STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS – RETAIL

| TARIFF CLASS | SERVICE VOLTAGE | COINCI-DENCE | LOAD FACTOR | ENERGY SHARES PEAK | MID-PEAK | TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW | ENERGY tysZl/KWh | TOTAL tysZl/KWh | DEMAND CHARGE SHARE | H1/1992 SALES GWh | CURRENT YIELD tysZl/KWh |
|---|---|---|---|---|---|---|---|---|---|---|---|
| INDUSTRIAL | HV | 0.81 | 0.60 | 0.16 | 0.27 | 98.09 | 0.4354 | 0.6594 | 34% | 14090 | 0.3874 |
| | MV | 0.63 | 0.42 | 0.18 | 0.31 | 117.62 | 0.4652 | 0.8488 | 45% | 8884 | 0.4995 |
| | LV | 0.54 | 0.31 | 0.18 | 0.31 | 154.27 | 0.5203 | 1.2020 | 57% | 1334 | 0.7828 |
| TRACTION | HV | 0.93 | 0.48 | 0.19 | 0.30 | 112.62 | 0.4534 | 0.7748 | 41% | 67 | 0.4606 |
| | MV | 0.93 | 0.48 | 0.19 | 0.30 | 173.63 | 0.4671 | 0.9627 | 51% | 2178 | 0.4715 |
| COMMERCIAL | MV | 0.63 | 0.49 | 0.20 | 0.32 | 117.62 | 0.4755 | 0.8044 | 41% | 641 | 0.4934 |
| | LV | 0.55 | 0.30 | 0.20 | 0.32 | 157.13 | 0.5323 | 1.2498 | 57% | 4464 | 0.7745 |
| AGRICULTURAL | MV | 0.54 | 0.38 | 0.20 | 0.32 | 100.82 | 0.4755 | 0.8390 | 43% | 320 | 0.5287 |
| RETAIL | LV | 0.49 | 0.25 | 0.27 | 0.25 | 139.99 | 0.5479 | 1.3150 | 58% | 13616 | 0.6310 |
| ST. LIGHTING | LV | 1.00 | 0.50 | 0.21 | 0.04 | 285.69 | 0.4659 | 1.2486 | 63% | 742 | 0.7884 |
| DISTRIBUTION COMPANY AVERAGE | | | | 0.20 | 0.28 | 128.31 | 0.4888 | 0.9879 | | 46336 | 0.5421 |
| Equivalent tysZl/KWh | | | | | | 0.4991 | 0.4888 | 0.9879 | | | |
| % of System Average | | | | | | 51% | 49% | 100% | | | |

| Variable | Sensitivity Range |
|---|---|
| Discount Rate | 8% - 14% |
| Standard Conversion Factor | 0.85 - 1.0 |
| Foreign Exchange Rate | 13000 - 19000 Zl/US$ |
| Planning Reserve Margin | 15% - 25% |
| Year Generation Required | 1996 - 1999 |
| Economic Price of Coal | $1.50 - $2.50/MMBtu |
| Size of T&D Investment Program | 0.6 - 1.0 times the Base Case |

Exhibit 7-15 summarizes the results of these sensitivities. The top row of each sensitivity test shows the LRMC -- PPGC bulk and distribution company retail -- with the base case value for that variable. Subsequent rows show how alternative values would alter the final result.

The average LRMC is most sensitive to changes in the foreign exchange rate, and to the T&D investment program. The exhibit graphs the sensitivity of these results. As the exchange rate moves from 13,400 Zl/$ (mid-1992) to 19,000 Zl/kWh, the retail (distribution company) LRMC increases from 988 to 1,302 Zl/kWh. Alternatively, a reduction in the total T&D investment program by 20 percent would reduce the retail LRMC from 988 to 919 Zl/kWh.

The LRMC is also sensitive to changes in the discount rate and the price of coal. A 2 percent increase (decrease) in the discount rate used in project analysis effectively increases (decreases) the retail LRMC by about 6 percent. A coal price rise from $2.12 to $2.50 per MMBtu ($2.01 to $2.37 per GJ) increases the average retail LRMC from 988 to 1,047 Zl/kWh.

Surprisingly, LRMC is relatively insensitive to differing reserve margin assumptions. At planning reserve margins in the range of 15 to 25 percent, the retail LRMC varies by less than 2 percent. It is also quite insensitive to expediting or delaying the year in which new generation is first required.

We did not calculate the sensitivity of LRMC to changes in projected load growth that might occur as a result of required electricity tariff increases. There are two major reasons *not* to do so. First, no reliable Poland-specific price elasticity data are available from which to estimate demand response. Second, any demand response will require a revised investment program in order to calculate the LRAIC of network capacity. In the absence of this information, tariff planning should continue based on the PPGC Scenario II ("low") load forecast.

Exhibit 7 - 15
LRMC SENSITIVITY ANALYSIS (tysZl/KWh)

| DISCOUNT RATE | Bulk LRMC | Retail LRMC |
|---|---|---|
| 12% | 0.7085 | 0.9879 |
| 8% | 0.6538 | 0.8768 |
| 10% | 0.6807 | 0.9311 |
| 12% | 0.7085 | 0.9879 |
| 14% | 0.7370 | 1.0468 |

| SCF | Bulk LRMC | Retail LRMC |
|---|---|---|
| 1.00 | 0.7085 | 0.9879 |
| 0.85 | 0.8193 | 1.1152 |
| 0.90 | 0.7783 | 1.0680 |
| 0.95 | 0.7416 | 1.0259 |
| 1.00 | 0.7085 | 0.9879 |

| EXCHANGE RATE | Bulk LRMC | Retail LRMC |
|---|---|---|
| 13.400 | 0.7085 | 0.9879 |
| 13.000 | 0.6890 | 0.9655 |
| 15.000 | 0.7867 | 1.0778 |
| 17.000 | 0.8844 | 1.1900 |
| 19.000 | 0.9821 | 1.3023 |

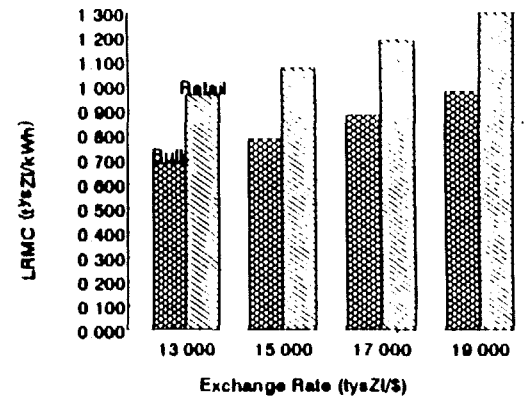
| YEAR GEN NEEDED | Bulk LRMC | Retail LRMC |
|---|---|---|
| 1997 | 0.7085 | 0.9879 |
| 1996 | 0.7244 | 1.0067 |
| 1997 | 0.7085 | 0.9879 |
| 1998 | 0.6943 | 0.9712 |
| 1999 | 0.6816 | 0.9563 |

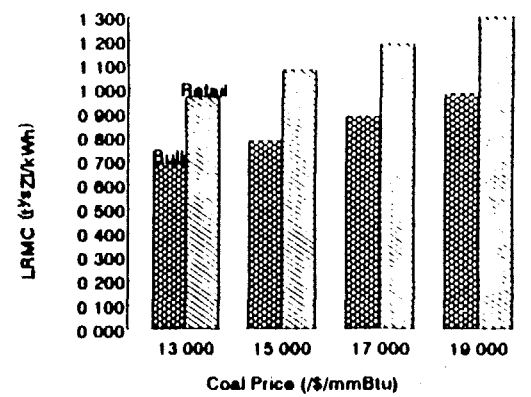
| COAL PRICE | Bulk LRMC | Retail LRMC |
|---|---|---|
| 2.12 | 0.7085 | 0.9879 |
| 1.50 | 0.6174 | 0.8913 |
| 1.75 | 0.6540 | 0.9301 |
| 2.00 | 0.6906 | 0.9690 |
| 2.25 | 0.7272 | 1.0078 |
| 2.50 | 0.7639 | 1.0467 |

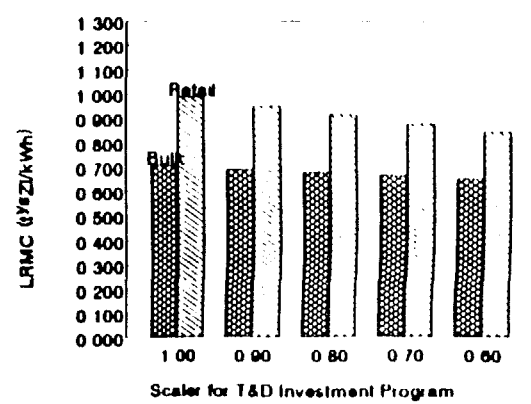
| RESERVE MARGIN | Bulk LRMC | Retail LRMC |
|---|---|---|
| 20.0% | 0.7085 | 0.9879 |
| 15.0% | 0.7030 | 0.9814 |
| 17.5% | 0.7057 | 0.9847 |
| 20.0% | 0.7085 | 0.9879 |
| 22.5% | 0.7113 | 0.9912 |
| 25.0% | 0.7140 | 0.9944 |

| T&D INVSTMNT | Bulk LRMC | Retail LRMC | T&D % of Capac Csts |
|---|---|---|---|
| 1.00 | 0.7085 | 0.9879 | 74% |
| 0.90 | 0.6963 | 0.9536 | 72% |
| 0.80 | 0.6840 | 0.9193 | 70% |
| 0.70 | 0.6718 | 0.8850 | 67% |
| 0.60 | 0.6596 | 0.8507 | 63% |

Note: Program must be "RUN" to update sensitivity analysis.

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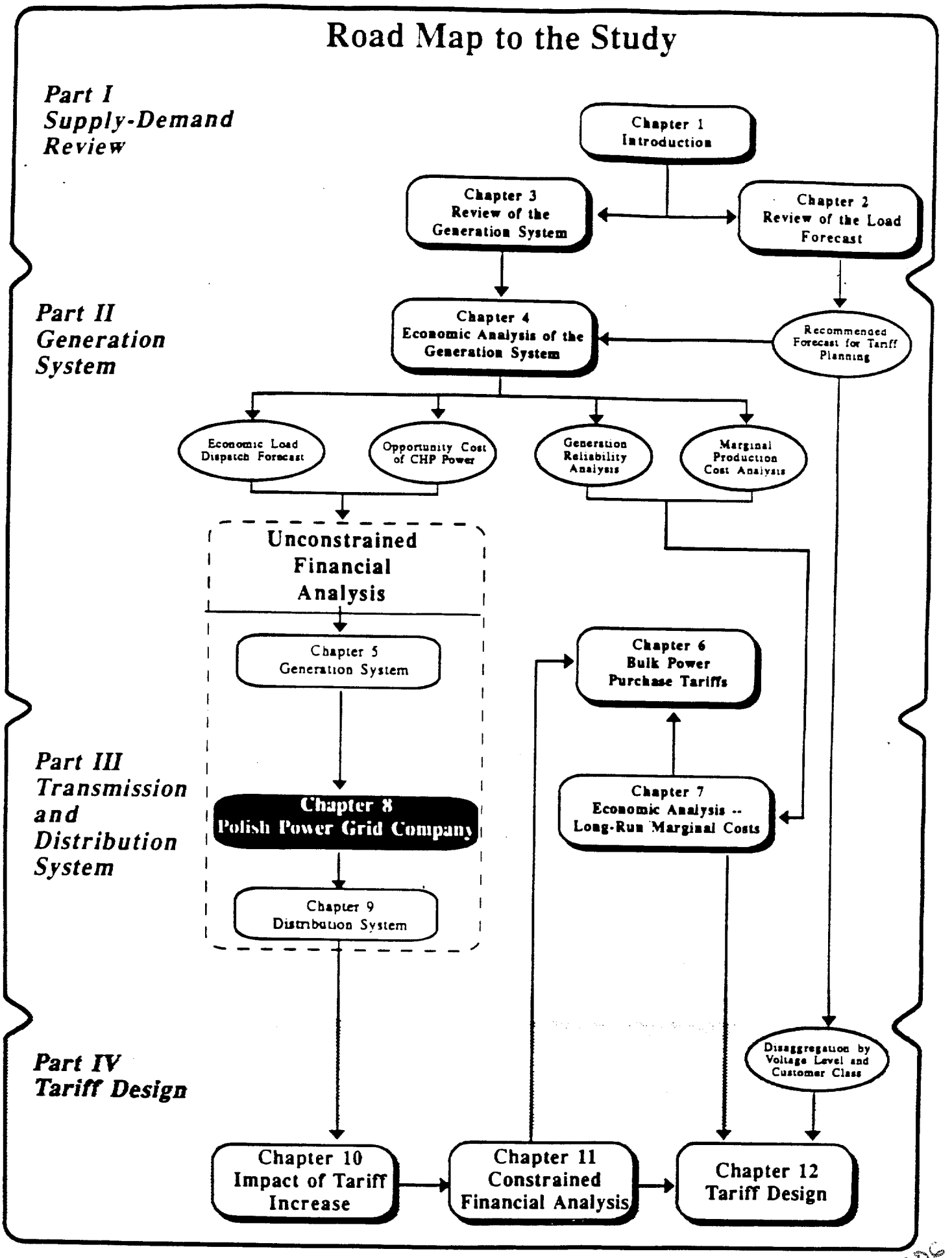
# Road Map to the Study



# Exhibit 8 – 3c
## FINANCIAL PERFORMANCE RATIOS – PPGC

| PRO - FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNE Year End – December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **DOMESTIC SALES** | | | | | | |
| | | 2 2% | Energy Sales(Gwh) Annual Growth % | -2 6% | 1 8% | 2 2% | 3 2% | 2 7% | 2 8% |
| | | | Sales Revenue(Zl) Annual Growth % | 50 3% | 1 9% | 70 7% | 2 1% | 3 1% | 5 0% |
| | | 218.2 | **Average Tariff Zl/kwh** | 336.7 | 337.0 | 563 0 | 557.0 | 559.0 | 571 0 |
| | | 218 2 | Average Energy Tariff Zl/kwh | 336 7 | 337 0 | 563 0 | 557 0 | 559 0 | 571 0 |
| | | | Av Capac Tariff - '000 Zl/MW/mo | | | | | | |
| | | | **INCOME RATIOS:** | | | | | | |
| | | | Op Income/ Net Assets % | | | | | | |
| | | 145 7% | BEFORE Transfer of Assets/Costs | 200 0% | | | | | |
| | | 7 2% | **AFTER Transfer of Assets/Costs** | 6.1% | 4.8% | 6.1% | 5.9% | 6 0% | 5 9% |
| | | | Op Income after Dep'n/ Sales % | | | | | | |
| | | 1 1% | BEFORE Transfer of Assets/Costs | 2 8% | | | | | |
| | | 0 1% | **AFTER Transfer of Assets/Costs** | 1.7% | -3 9% | 2.8% | 2.6% | 2 6% | 2 5% |
| | | | Net Income/ Total Equity % | | | | | | |
| | | 21 7% | BEFORE Transfer of Assets/Costs | 1 8% | | | | | |
| | | 23 6% | AFTER Transfer of Assets/Costs | 2.1% | -3 0% | 3 3% | 2 8% | 2 5% | 2 2% |
| | | | **CASH FLOW RATIOS:** | | | | | | |
| | | | Debt Service Ratio | | | | | | |
| | | 8 10 | BEFORE Transfer of Assets/Costs | 10 73 | -26 69 | 8 29 | 4 33 | 3 48 | 3 02 |
| | | | **Self Financing Ratio** | | | | | | |
| | | 64 4% | BEFORE Transfer of Assets/Costs | 98 0% | 78 7% | 40 2% | 24 7% | 29 2% | 99 8% |
| | | | **BALANCE SHEET RATIOS:** | | | | | | |
| | | 1 78 | Current Ratio | 1.86 | 2 53 | 3 75 | 4 90 | 5 83 | 6 72 |
| | | 0 01 | Cash at Bank to Sales months | 0 01 | 0 30 | 0 73 | 1 25 | 1 66 | 2 05 |
| | | 0 93 | Accts Receivable to Sales months | 0 92 | 0 92 | 0 92 | 0 92 | 0 92 | 0 92 |
| | | | Debt to Equity Ratio - % | | | | | | |
| | | 28 0% | BEFORE Transfer of Assets/Costs | 2 6% | | | | | |
| | | | AFTER Transfer of Assets/Costs | | 4 3% | 13 8% | 24 3% | 32 7% | 31 6% |

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## 8.3 FINANCIAL REVENUE REQUIREMENTS OF PPGC

### 8.3.1 Transfer of Assets

In projecting the results for 1993-1997, PPGC's fixed assets were revalued and increased effective January 1, 1993 by 57.207 billion zloties, representing the 1992 valuation of distribution assets transferred from the distribution companies to PPGC. The gross book value of the assets transferred can be summarized as follows:

| Asset | Billion Zloties | |
|---|---|---|
| | At 1990 Book Value | At 1992 Revaluation |
| Lines > 100 kV | 4.163 | 24.644 |
| Substations | 3.002 | 13.007 |
| Subtotal | 7.165 | 37.651 |
| Pumped Storage Plants | 3.339 | 19.556 |
| Total | 10.504 | 57.207 |

The revalued depreciation amounted to 52 percent of the revalued gross book value. It was assumed that the asset transfer represented an *equity* contribution to PPGC.

### 8.3.2 Financial Criteria to be Met

The key financial target to be achieved by PPGC was assumed to be the same as for the generating companies: 6.0 percent return on net assets employed (i.e., working capital plus fixed assets valued at depreciated replacement cost).

### 8.3.3 Assumptions and Data Sources

Assumptions similar to those for the generating companies were adopted for PPGE.

- The financial forecast was developed at mid-1992 price levels and exchange rate of 13.400 Zl to the US dollar.

- The financial forecast was developed at mid-1992 price levels and exchange rate of 13,400 Zl to the US dollar.

- The purchase price of electricity is the weighted average of the selling price by the system power plants -- i.e., 489 Zl/kWh in 1994 and the "avoided cost" that would be paid to the CHP plants, assumed to be 603 Zl/kWh, or 4.5 US cents/kWh, as discussed in Chapter 4.

- The PPGC capital investment program is the program provided by the PPGC Investment Planning Department.

- PPGC's 1992 cost estimate is based on the revised budget prepared by the PPGC Finance Department in November 1992.

- The costs for 1993 and future years are based on the 1992 budget plus costs associated with the transferred assets, as developed by Energoprojekt.

- System losses overall are assumed to be approximately 2.5 percent, which comprises approximately 1.8 percent in the transmission network and approximately 0.7 percent in pumped storage.

## 8.4 RESULTS

The results presented in this section are those for the unconstrained tariff increase and instant asset revaluation scenario. See Chapter 11 for results under the financial forecast constrained by the need to limit the impact of tariff increases and the feasible extent of and schedule for the revaluation of assets.

In Exhibit 8-1 the forecast energy balance of PPGC is presented for the period 1992-1997; Exhibit 8-2 contains a forecast of revenues and revenues from sales and the cost of energy sold. In Exhibits 8-3a, 8-3b, and 8-3c, the income statement, balance sheet and financial performance ratios of PPGC are shown.

Based on the average purchase price to the generating companies of 489 Zl/kWh forecast for 1994 and the avoided cost to CHP plants estimated at 603 Zl/kWh, the revenue requirement that PPGC needs to provide a return of 6.0 percent on its revalued net assets is 563 Zl/kWh. All these are expressed at 1992 price levels.

Considering the mid-1992 average bulk purchase sale price of 337 Zl/kWh, this represents a real increase of 67 percent.

Exhibit 8-1
ENERGY BALANCE OF PPGC

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNI Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **Total Energy Sales by Distrbn Cos** | | | | | | |
| 65,405 | 57,312 | 51,052 | Industry | 48,988 | 48,864 | 48,843 | 49,300 | 50,410 | 51,612 |
| 5,875 | 5,346 | 4,915 | Railways | 5,160 | 5,631 | 6,158 | 6,800 | 6,940 | 7,092 |
| 9,386 | 8,218 | 9,821 | Commercial | 9,192 | 9,676 | 10,206 | 10,871 | 11,201 | 11,556 |
| 8,633 | 8,124 | 8,394 | Agriculture | 8,422 | 8,865 | 9,351 | 9,960 | 10,262 | 10,587 |
| 20,267 | 22,183 | 20,829 | Residential | 21,937 | 23,091 | 24,356 | 25,943 | 26,731 | 27,578 |
| 28,900 | 30,307 | 29,223 | Sub total - Agricult & Resid'l | 30,359 | 31,956 | 33,707 | 35,903 | 36,993 | 38,165 |
| 1,506 | 1,325 | 1,372 | Street Lighting | 1,375 | 1,448 | 1,527 | 1,627 | 1,676 | 1,729 |
| **111,072** | **102,506** | **96,383** | **TOTAL FINAL CONSUMPTION** | **95,074** | **97,575** | **100,441** | **104,501** | **107,220** | **110,154** |
| | | | Distribution System Losses -- % | | | | | | |
| 13,345 | 9,235 | 14,597 | Distribution System Losses | 11,237 | 10,659 | 10,156 | 9,579 | 9,919 | 10,207 |
| | | 1,891 | Distribution Co's Own Generation | | | | | | |
| | | | **Total Distribution Co Purchases:** | | | | | | |
| 124,013 | 111,235 | 108,733 | From Grid (PSE) | 105,911 | 107,834 | 110,197 | 113,680 | 116,739 | 119,961 |
| 396 | 495 | 339 | From Self Producers | 400 | 400 | 400 | 400 | 400 | 400 |
| 8 | 13 | 17 | From Small Hydro | | | | | | |
| 124,417 | 111,743 | 109,089 | Total Purchases | 106,311 | 108,234 | 110,597 | 114,080 | 117,139 | 120,361 |
| | | | **Total Energy Sales by Grid:** | | | | | | |
| 124,013 | 111,235 | 108,733 | Distribution Companies | 105,911 | 107,834 | 110,197 | 113,680 | 116,739 | 119,961 |
| 10,268 | 11,477 | 9,326 | Exports | | | | | | |
| **134,281** | **122,712** | **118,059** | **TOTAL PSE SALES** | **105,911** | **107,834** | **110,197** | **113,680** | **116,739** | **119,961** |
| 777 | 717 | 785 | Pumped Storage Usage (Net) | 750 | 750 | 750 | 750 | 750 | 750 |
| 0 | 0 | 0 | Transmission Losses -- % | 0 | 0 | 0 | 0 | 0 | 0 |
| 2,145 | 4,025 | 3,642 | Transmission Losses | 2,253 | 2,137 | 2,036 | 1,921 | 1,988 | 2,046 |
| **137,203** | **127,454** | **122,486** | **TOTAL PSE PURCHASES** | **108,914** | **110,721** | **112,983** | **116,351** | **119,477** | **122,757** |
| 12,059 | 10,437 | 6,708 | Imports | | | | | | |
| 125,144 | 117,017 | 115,778 | Domestic Purchases: | 108,914 | 110,721 | 112,983 | 116,351 | 119,477 | 122,757 |
| 123,540 | 115,614 | 114,347 | System Thermal Plants | 94,913 | 96,387 | 97,983 | 100,352 | 102,208 | 103,219 |
| | | | CHP & Collector Plants | 12,570 | 12,903 | 13,569 | 14,568 | 15,838 | 18,107 |
| 1,604 | 1,403 | 1,431 | Hydro - generation | 1,431 | 1,431 | 1,431 | 1,431 | 1,431 | 1,431 |
| | | | Unexplained Difference | | | | | | |

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## Exhibit 8-2
## REVENUE AND COST OF SALES OF PPGC

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNI Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **REVENUE AND COST OF SALES** | | | | | | |
| | | | Domestic Demand -- MW | | | | | | |
| 124,013 | 111,235 | 108,733 | Domestic Energy Sales -- GWH | 105,911 | 107,834 | 110,197 | 113,680 | 116,739 | 119,961 |
| (1,791) | 1,040 | 2,618 | Net Export Energy Sales -- GWH | | | | | | |
| 2 33% | 4 05% | 3.82% | System Losses -- % | 2.76% | 2 61% | 2 47% | 2 30% | 2 29% | 2 28% |
| 125,144 | 117,017 | 115,778 | Domestic Energy Purchases -- GWh | 108,914 | 110,721 | 112,983 | 116,351 | 119,477 | 122,757 |
| | | 235,072 8 | Capacity Purchases -- MW | 231,828 4 | 231,828 4 | | | | |
| | | 769 | No of Employees | | | | | | |
| | | | Domestic Tariff -- 000 Zl / MW | | | | | | |
| | | 218 230 | -- 000 Zl / kwh | 336,716 | 337 000 | 563 000 | 557 000 | 559 000 | 571 000 |
| | | 333 290 | Export Tariff(Av Net) -- 000 Zl/kwh | | | | | | |
| | | | **Revenues from Sales:** | | | | | | |
| | | 23,729 | Domestic | 35,662 | 36,340 | 62,041 | 63,320 | 65,257 | 68,497 |
| | | | Demand | | | | | | |
| | | 23,729 | Energy | 35,662 | 36,340 | 62,041 | 63,320 | 65,257 | 68,497 |
| | | 873 | Net Export Revenue | | | | | | |
| | | | Demand | | | | | | |
| | | 873 | Energy | | | | | | |
| | | 52 | Other (Services, Domestic/Export) | | | | | | |
| | | 24,653 | **Total Sales** | 35,662 | 36,340 | 62,041 | 63,320 | 65,257 | 68,497 |
| | | | Purchase Tariffs from Generators | | | | | | |
| | | 46 848 | Capacity Payment -- 000 Zl / MW | 57,590 | 57 590 | | | | |
| | | 110 211 | Energy Payment -- system Zl / kwh | 186 000 | 186 000 | 488 951 | 487 195 | 490 566 | 504 206 |
| | | | Energy Payment -- CHP Zl / kwh | 186 000 | 186 000 | 603 000 | 603 000 | 603 000 | 603 000 |
| | | | Energy Payment -- hydro Zl / kwh | 336 716 | 337 000 | 653 000 | 447 000 | 559 000 | 571 000 |
| | | | **Cost of Sales:** | | | | | | |
| | | 11,013 | Capacity payments | 13,351 | 13,351 | 0 | 0 | 0 | 0 |
| | | 12,760 | Energy Purchases - system plants | 17,654 | 17,928 | 47,909 | 48,891 | 50,140 | 52,043 |
| | | | Energy Purchases CHP plants | 2,338 | 2,400 | 8,182 | 8,785 | 9,550 | 10,919 |
| | | | Energy Purchases hydro plants | 482 | 482 | 806 | 797 | 800 | 817 |
| | | (98) | Penalty to GenCos for Shortfall | | | | | | |
| | | 341 | System Control Costs | | | | | | |
| | | 24,015 | **Total Cost of Sales** | 34,329 | 34,161 | 56,897 | 58,473 | 60,490 | 63,779 |

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## Exhibit 8 - 3a
## INCOME STATEMENT - PPGC

| PRO - FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNI Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **INCOME STATEMENT** | | | | | | |
| | | 24,653 | Total Sales | 35,662 | 36,340 | 62,041 | 63,320 | 65,257 | 68,497 |
| | | 24,015 | Total Cost of Sales | 34,329 | 34,161 | 56,897 | 58,473 | 60,490 | 63,797 |
| | | 638 | Net Revenue from Energy Sales | 1,333 | 2,179 | 5,144 | 4,847 | 4,767 | 4,718 |
| | | 141 | Materials & Energy | 166 | | | | | |
| | | 147 | Outside Services | 94 | | | | | |
| | | 35 | Salaries / Payroll | 62 | | | | | |
| | | 22 | Payroll Taxes, etc | 30 | | | | | |
| | | 2 | Business Travel | 2 | | | | | |
| | | 7 | Other | | | | | | |
| | | 354 | **Total Overhead Costs @1992 Prices** | 354 | | | | | |
| | | | Inflation | | | | | | |
| | | | Total @ Current Prices | 354 | | | | | |
| | | | Plus Transfers from Distribution Cos | | | | | | |
| | | 9 | Materials & Energy | 12 | | | | | |
| | | 54 | Outside Services | 75 | | | | | |
| | | 39 | Salaries / Payroll | 54 | | | | | |
| | | | Payroll Taxes, etc | | | | | | |
| | | | Business Travel | | | | | | |
| | | 56 | Pumped Storage Costs | 69 | | | | | |
| | | 143 | Other | 198 | | | | | |
| | | 301 | Total O'head Costs Transf'd @1992 Prices | 407 | | | | | |
| | | | Inflation | | | | | | |
| | | | **Total O'head Costs Transferred** | 407 | | | | | |
| | | | Adjusted Total Overhead Costs: | | | | | | |
| | | 150 | Materials & Energy | 178 | 178 | 178 | 178 | 178 | 178 |
| | | 201 | Outside Services | 169 | 169 | 169 | 169 | 169 | 169 |
| | | 74 | Salaries / Payroll | 116 | 116 | 116 | 116 | 116 | 116 |
| | | 22 | Payroll Taxes, etc | 30 | 30 | 30 | 30 | 30 | 30 |
| | | 2 | Business Travel | 2 | 2 | 2 | 2 | 2 | 2 |
| | | 64 | Pumped Storage Costs | 69 | 69 | 69 | 69 | 69 | 69 |
| | | 151 | Other | 198 | 198 | 198 | 198 | 198 | 198 |
| | | 662 | **Total Adjusted O'head Costs @1992** | 761 | 761 | 761 | 761 | 761 | 761 |
| | | | Inflation | | | | | | |
| | | | **Total @ Current Prices** | 761 | 761 | 761 | 761 | 761 | 761 |
| | | 13 | Other Costs | | | | | | |
| | | 271 | Net Revenue from Production | 979 | | | | | |

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## Exhibit 8 – 3a
## INCOME STATEMENT – PPGC

| PRO FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNE Year End – – December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | (BEFORE TRANSFERRED COSTS) | | | | | | |
| | | | Net Revenue from Production | | 1,418 | 4,383 | 4,086 | 4,006 | 3,957 |
| | | | (AFTER TRANSFERRED COSTS) | | | | | | |
| | | 10 | Interest from loans to Others | | | | | | |
| | | 130 | Interest on Deposits at Bank | 2 | 51 | 258 | 569 | 857 | 1,139 |
| | | 2 | Gain on Currency Exchange | | | | | | |
| | | 142 | **Financial Income/ Interest Income** | 2 | 51 | 258 | 569 | 857 | 1,139 |
| | | 1 | Other Revenues | 17 | | | | | |
| | | 414 | Operating Income | 998 | | | | | |
| | | | (BEFORE TRANSFERRED COSTS) | | | | | | |
| | | | Operating Income | | 1,469 | 4,641 | 4,655 | 4,863 | 5,096 |
| | | | (AFTER TRANSFERRED COSTS) | | | | | | |
| | | 11 | Depreciation – – per Statement | 15 | 22 | 59 | 147 | 309 | 509 |
| | | | Plus: Dep'n on Revaluation | | | | | | |
| | | | **Total Dep'n @ Current Prices** | 15 | 22 | 59 | 147 | 309 | 509 |
| | | 469 | Depreciation – – Transferred from DCs | | 525 | 525 | 525 | 525 | 525 |
| | | | Plus: Dep'n on Revaluation | | 2,329 | 2,337 | 2,337 | 2,337 | 2,337 |
| | | | **Total Dep'n @ Current Prices** | | 2,854 | 2,863 | 2,863 | 2,863 | 2,863 |
| | | 480 | Total Adjusted Depreciation @1992 | 15 | 547 | 584 | 672 | 834 | 1,034 |
| | | | Plus: Dep'n on Revaluation | | 2,329 | 2,337 | 2,337 | 2,337 | 2,337 |
| | | | **Total Dep'n @ Current Prices** | 15 | 2,875 | 2,922 | 3,009 | 3,172 | 3,372 |
| | | | Operating Income after Deprec'n | 983 | (1,406) | 1,719 | 1,646 | 1,692 | 1,724 |
| | | | **Financial Charges:** | | | | | | |
| | | 6 | Lease Payments | | | | | | |
| | | 27 | Long Term Loan Interest | 59 | 107 | 286 | 619 | 949 | 1,128 |
| | | | Less: Interest during Construction | | 77 | 148 | 330 | 520 | 538 |
| | | | Net Interest | 59 | 30 | 138 | 289 | 429 | 589 |
| | | 371 | Income before Tax | 925 | (1,437) | 1,581 | 1,357 | 1,262 | 1,135 |
| | | 148 | Income Tax | 370 | (575) | 632 | 543 | 505 | 454 |
| | | | Capital Tax | | | | | | |
| | | 1 | Other Taxes | | | | | | |
| | | 221 | NET INCOME (BEFORE TRANSFERS) | 555 | (862) | 949 | 814 | 757 | 681 |

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Exhibit 8-3b
BALANCE SHEET - PPGC

| PRO FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNE Year End - December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **ASSETS** | | | | | | |
| | | | **Fixed Assets:** | | | | | | |
| | | | Capital Assets | | | | | | |
| | 179 | 180 | Gross Fixed Assets | 180 | 680 | 1,680 | 4,180 | 8,180 | 12,180 |
| | | | Plus Transfers of Grid from DCs | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 |
| | | | Plus Transfers of Pumped Storage | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 |
| | | | **Total Adjusted Gross Fixed Assets** | **10,685** | **11,185** | **12,185** | **14,685** | **18,685** | **22,685** |
| | | | Plus Revaluation to 1992 | 46,397 | 46,746 | 46,746 | 46,746 | 46,746 | 46,746 |
| | | | Plus Revaluation after 1992 | | | | | | |
| | | | Revalued Gross Fixed Assets | 57,082 | 57,931 | 58,931 | 61,431 | 65,431 | 69,431 |
| | 91 | 95 | Less Accumulated Depreciatn | 110 | 132 | 191 | 337 | 646 | 1,155 |
| | | | Depreciation on Transfers | 5,483 | 6,008 | 6,533 | 7,059 | 7,584 | 8,109 |
| | | | Revalued Depreciation | 24,217 | 26,545 | 28,883 | 31,220 | 33,557 | 35,894 |
| | | | Depreciation on Revaluation | | | | | | |
| | | | **Total Accumulated Depreciationn** | **29,810** | **32,685** | **35,607** | **38,616** | **41,787** | **45,159** |
| | 88 | 85 | Net Fixed Assets | 27,272 | 25,246 | 23,324 | 22,815 | 23,644 | 24,272 |
| | 3 | 130 | Capital Work in Progress | 699 | 1,344 | 3,000 | 4,723 | 4,895 | 2,627 |
| | 1 | 185 | Advance Payments | 197 | 197 | 197 | 197 | 197 | 197 |
| | | 1 | Patents & Licenses | 1 | 1 | 1 | 1 | 1 | 1 |
| | | | **Financial Investments:** | | | | | | |
| | | 0 | Shares in other Companies | | | | | | |
| | 221 | 193 | Long Term Accounts Receivable | 193 | 193 | 193 | 193 | 193 | 193 |
| | | | **Current Assets:** | | | | | | |
| | 0 | 0 | Inventories | | | | | | |
| | 247 | 1,905 | Accounts Receivable | 2,736 | 2,788 | 4,759 | 4,857 | 5,006 | 5,255 |
| | 24 | 0 | Income Tax Receivable | | | | | | |
| | 5 | 5 | Other Accounts Receivable | | | | | | |
| | 590 | 25 | Cash at Bank and on Deposit | 15 | 917 | 3,769 | 6,578 | 9,007 | 11,697 |
| | **668** | **1,936** | **Total Current Assets** | **2,751** | **3,704** | **8,529** | **11,435** | **14,013** | **16,952** |
| | **1,180** | **2,530** | **TOTAL ASSETS** | **31,114** | **30,686** | **35,245** | **39,365** | **42,944** | **44,243** |

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Exhibit 8-3b

BALANCE SHEET - PPGC

| PRO - FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | LIABILITIES | | | | | | |
| | | | Equity Capital: | | | | | | |
| | 515 | 515 | Equity | 515 | 515 | 515 | 515 | 515 | 515 |
| | 71 | 389 | Reserve Capital | 610 | 1,165 | 303 | 1,252 | 2,066 | 2,823 |
| | | | Transfers of Grid from DCs | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 |
| | | | Transfer of Pumped Storage | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 |
| | | | Less: Accum. dep'n on Transfers | 5,483 | 5,483 | 5,483 | 5,483 | 5,483 | 5,483 |
| | 1 | | Asset Revaluation | 22,180 | 22,180 | 22,180 | 22,180 | 22,180 | 22,180 |
| | 321 | 221 | Current Year's Net Income | 555 | (862) | 949 | 614 | 757 | 681 |
| | 906 | 1,125 | Total Equity | 28,882 | 28,020 | 28,968 | 29,783 | 30,540 | 31,221 |
| | | 315 | Long Term Debt | 750 | 1,200 | 4,000 | 7,250 | 10,000 | 10,500 |
| | | | Current Liabilities: | | | | | | |
| | 231 | 841 | Accounts Payable | 1,232 | 1,217 | 2,026 | 2,083 | 2,154 | 2,272 |
| | 6 | 112 | Other Accounts Payable | 110 | 110 | 110 | 110 | 110 | 110 |
| | | | Short Term Loans | | | | | | |
| | 35 | 138 | Other Liabilities | 140 | 140 | 140 | 140 | 140 | 140 |
| | | | Owing to Bank | | | | | | |
| | 271 | 1,091 | Total Current Liabilities | 1,482 | 1,467 | 2,276 | 2,333 | 2,404 | 2,522 |
| | 1,180 | 2,531 | TOTAL LIABILITIES | 31,114 | 30,686 | 35,245 | 39,365 | 42,944 | 44,243 |
| | 179 | 180 | Gross Fixed Assets | 180 | 680 | 1,680 | 4,180 | 8,180 | 12,180 |
| | 6,903 | 6,903 | Plus: Transfers of Grid from DCs | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 |
| | | 3,252 | Plus: Transfers of Pumped Storage | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 |
| | 7,082 | 7,084 | Total Adjusted Gross Fixed Assets | 10,685 | 11,185 | 12,185 | 14,685 | 18,685 | 22,685 |

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## Exhibit 8 – 3c
## FINANCIAL PERFORMANCE RATIOS - PPGC

| PRO - FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNE Year End — December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **DOMESTIC SALES:** | | | | | | |
| | | 2 2% | Energy Sales(Gwh) Annual Growth % | -2 6% | 1 8% | 2 2% | 3 2% | 2 7% | 2 8% |
| | | | Sales Revenue(Zl) Annual Growth % | 50 3% | 1 9% | 70 7% | 2 1% | 3 1% | 5 0% |
| | | 218.2 | **Average Tariff Zl/kwh** | 336.7 | 337.0 | 563 0 | 557 0 | 559.0 | 571 0 |
| | | 218 2 | Average Energy Tariff Zl/kwh | 336 7 | 337 0 | 563 0 | 557 0 | 559 0 | 571 0 |
| | | | Av Capac Tariff - '000 Zl/MW/mo | | | | | | |
| | | | **INCOME RATIOS:** | | | | | | |
| | | | Op Income/ Net Assets % | | | | | | |
| | | 145 7% | BEFORE Transfer of Assets/Costs | 200 0% | | | | | |
| | | 7 2% | **AFTER Transfer of Assets/Costs** | 6.1% | 4 8% | 6.1% | 5.9% | 6 0% | 5 9% |
| | | | Op Income after Dep'n/ Sales % | | | | | | |
| | | 1 1% | BEFORE Transfer of Assets/Costs | 2 8% | | | | | |
| | | 0 1% | **AFTER Transfer of Assets/Costs** | 1.7% | -3 9% | 2.8% | 2.6% | 2 6% | 2 5% |
| | | | Net Income/ Total Equity % | | | | | | |
| | | 21 7% | BEFORE Transfer of Assets/Costs | 1.8% | | | | | |
| | | 23 6% | AFTER Transfer of Assets/Costs | 2.1% | -3 0% | 3 3% | 2 8% | 2 5% | 2 2% |
| | | | **CASH FLOW RATIOS:** | | | | | | |
| | | | Debt Service Ratio | | | | | | |
| | | 8 10 | BEFORE Transfer of Assets/Costs | 10 73 | -26 69 | 8 29 | 4 33 | 3 48 | 3 02 |
| | | | **Self Financing Ratio** | | | | | | |
| | | 64 4% | BEFORE Transfer of Assets/Costs | 98.0% | -78 7% | 40 2% | 24 7% | 29 2% | 99 8% |
| | | | **BALANCE SHEET RATIOS:** | | | | | | |
| | | 1 78 | Current Ratio | 1.86 | 2 53 | 3 75 | 4 90 | 5 83 | 6 72 |
| | | 0 01 | Cash at Bank to Sales - months | 0 01 | 0 30 | 0 73 | 1 25 | 1 66 | 2 05 |
| | | 0 93 | Accts Receivable to Sales months | 0 92 | 0 92 | 0 92 | 0 92 | 0 92 | 0 92 |
| | | | Debt to Equity Ratio -- % | | | | | | |
| | | 28 0% | BEFORE Transfer of Assets/Costs | 2 6% | | | | | |
| | | | AFTER Transfer of Assets/Costs | | 4 3% | 13 8% | 24 3% | 32 7% | 33 6% |

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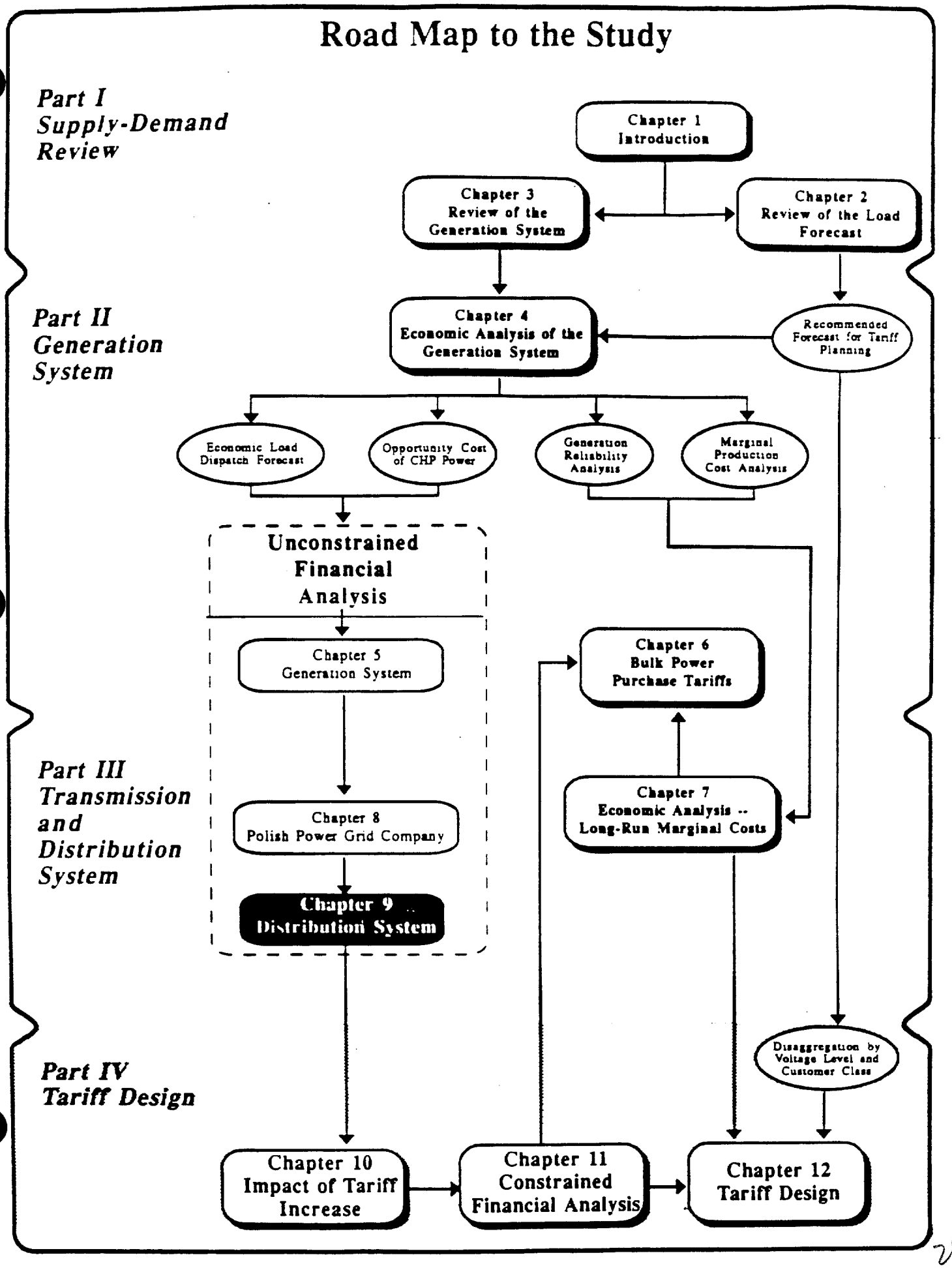
# Road Map to the Study



# CHAPTER 9: UNCONSTRAINED FINANCIAL ANALYSIS OF THE DISTRIBUTION SYSTEM

## 9.1 OBJECTIVES AND APPROACH

In this chapter, the financial requirements for the total distribution system and the resulting average system-wide tariff at the distribution level are developed with an emphasis on 1994. As was done with the generating system in Chapter 5 and the transmission grid in Chapter 8, the objective was to determine the revenue requirements of the distribution system so that this system can become a viable commercial activity.

As in Chapter 5, the financial forecast of Chapter 9 corresponds to a scenario of *unconstrained* tariff increase and instant asset revaluation. In Chapter 11, these results are subjected to different assumptions in order to arrive at a financial forecast that is constrained by the need to limit the impacts of tariff increases and by the feasible extent of and schedule for the revaluation of assets.

It is the Polish Government's policy to adopt uniform bulk sales tariffs for all distribution companies and allow each company to set its retail tariffs based on a regulated profit but according to the specific cost structure of each company. It is relevant to the objectives of this study to determine the variability that can be expected among the average retail tariffs of different distribution companies. Therefore, in addition to the consolidated case, three individual distribution companies were analyzed -- namely Warsaw, Gliwice and Bialystok -- which represent major urban, mid-size urban, and rural distribution companies.

The analysis of distribution costs and the required financial revenues and *average* tariff at the level of the distribution company customers was based on a consolidation or aggregation of key income statement and balance sheet data for the 33 distribution companies.

The consolidation was prepared by the Economics Department of PPGC from the "F-02" accounting returns from the individual distribution companies.

The analysis of 1989-1992 includes high-voltage lines and substations that were carried on the books of the distribution companies before being transferred to PPGC in January 1993.

## 9.2 HISTORICAL FINANCIAL REVIEW AND ANALYSIS

It should be noted that the 1989-1992 analysis includes high-voltage transmission assets. Thus, in 1991, distribution losses shown at 11.65 percent include losses attributable to transmission, which are estimated at approximately 2.0 percent.

### 9.2.1 Income Ratios

The ratios between the average selling tariff of the distribution companies and their average purchase cost from PPGC are as follows:

| | 1989 | 1990 | 1991 | 1992 (est.) |
|---|---|---|---|---|
| Average Selling Tariff (Zl/kWh) | 19.9 | 213.4 | 354.0 | 542.1 |
| Average Purchase Cost (Zl/kWh) | n.a. | 135.3 | 221.7 | 339.1 |
| Ratio (percent) | n.a. | 157.7 | 159.7 | 159.9 |

In 1990 and 1991, the ratios of operating income to sales (after allowing for depreciation based upon the 1990 PSO (Polish Statistical Office) asset revaluation were 10.4 percent and 8.4 percent, respectively. This, in turn, amounted to an operating income to net assets return of 3.4 percent and 3.9 percent, respectively.

It is worth noting that consistency has been maintained in these ratios despite the massive inflation that has occurred between 1989 and 1992.

### 9.2.2 Balance Sheet Ratios

The total net assets employed in the Polish distribution system in 1991 amounted to approximately 42,272 billion Zlotys (based on the 1990 PSO revaluation). Long-term debt totalled 1,309 billion Zlotys. This amounted to a debt-to-equity ratio of about 4 percent.

At least three different financial criteria are possible for the distribution system. They correspond to different levels of risk and different possibilities of financing, and result in different revenue requirements.

### Criterion A - No Net Increase in Overall Debt

This criterion requires that there be no net change in borrowing or indebtedness over the 1993-1997 period (a four-year period), although short-term borrowing to smooth out fluctuations is allowed in the intervening years. This criterion means that all capital expenditures plus all working capital increases must be paid for from cash flow, taking the four years in total. The distribution system must thus be capable of financing its equipment replacement and extending its service coverage from its revenues.

This is unquestionably the most prudent policy because it assumes that distribution utilities will not borrow on a long-term basis. Because of the stringency of this criterion, it will tend to result in a higher tariff than the other two criteria.

### Criterion B - 6 Percent Return on Net Assets

A 6 percent return on net assets for distribution companies was considered only because this would provide a consistent criterion throughout the power system, from generation to distribution. However, this criterion could result in highly volatile tariffs because the effects of capital expenditures in distribution are magnified by the effect of a 60 percent tax rate on the pre-tax profits of distribution companies.

### Criterion C - 100 Percent Self-Financing Ratio

The self-financing ratio is defined here as the net cash generation (i.e., depreciation plus net profit after taxes) divided by the average of three years of capital expenditure in the previous, current, and following years.

This definition, however, ignores any requirement to finance *working* capital (that is, increases in accounts receivable and inventories). In other words, a self-financing ratio of 100 percent would mean that only the cost of fixed *capital* expenditure is paid for from internal cash flow. Increases in working capital could still be financed by increased bank borrowing.

### 9.3.3 Assumptions and Sources of Data

The following are the major assumptions and sources of data used in the analysis of distribution companies:

- The historical data for the income statement and balance sheet were entered from a consolidation of the "F-02" statements for the distribution companies.

- The forecast energy sales were developed by Hagler, Bailly in conjunction with PPGC. They are described in Chapter 2.

- All projections of costs are in constant, mid-1992 price levels (equivalent to US $1.00 equals 13,400 Zlotys).

- Energy purchase costs were input from the results of the financial analysis of the transmission grid in Chapter 8.

- Operating costs for 1992 and subsequent years were based on 1991 costs (adjusted for the transfer of transmission assets) plus an inflation provision of 38 percent from 1991 to 1992. Given the companies' flat or modestly increasing sales, the real operating costs were projected to remain unchanged from 1992 levels.

- Annual depreciation expense was computed at 5.0 percent of average gross fixed assets in service.

- Interest expense (net of inflation) was computed at 11.0 percent per annum, based on average outstanding debt.

- From 1993 onwards, capital expenditure was assumed to be the sum of two components: 1) a component proportional to sales growth and the existing gross fixed assets in service and 2) replacement and modernization at 3.33 percent of existing gross assets. Assets were assumed, on average, to be placed in service 12 months after initial expenditure.

- Working capital is based on 2.0 months' sales in accounts receivable. This is higher than in the past; however, as the economy becomes increasingly privatized, it is likely that the trend will be towards an increase in average outstanding receivables (which were just under 1 month in 1991).

To avoid fluctuations over the period 1994-1997 due to annual changes in the revenue requirements of the generation system and the transmission grid, the average retail tariff was levelized by short-term borrowing rather than maintaining a uniform ratio with the bulk tariff.

## 9.4 RESULTS FOR THE CONSOLIDATED DISTRIBUTION SYSTEM

Exhibit 9-1 shows a balance of energy sales and purchases for the consolidated distribution companies. Exhibits 9-2a and 9-2b correspond to the income statement and balance sheet, respectively, for the consolidated distribution system, using the financial criterion of no net increase in overall debt (criterion A), as discussed above.

The application of the financial criterion of no net increase in debt to the forecast costs and capital expenditures results in revenue requirements of 785 Zl/kWh for the period 1994-1995. This represents the required average retail tariff at price levels of 1992 and is equivalent to 5.9 US cents/kWh. Compared with the mid-1992 average retail tariff, this represents a real increase of 45 percent. Using this criterion, the operating and financial ratios for the consolidated system are shown in Exhibit 9-2c.

The operating and financial ratios of the consolidated distribution companies using the 6 percent return on net assets criterion are presented in Exhibit 9-2d. Using this criterion, the forecast revenue requirements at the retail level would be 847 Zl/kWh in 1994, or a 56 percent increase from mid-1992 levels.

The operating and financial ratios of the consolidated distribution companies using the 100 percent self-financing ratio criterion are presented in Exhibit 9-2e. Using this criterion, the forecast revenue requirements at the retail level would be 739 Zl/kWh in 1994 or a 36 percent increase from mid-1992 levels.

The results presented below are those for the unconstrained tariff increase and instant asset revaluation scenario. See Chapter 11 for results under the financial forecast constrained by the need to limit the impact of tariff increases and the feasible extent of and schedule for the revaluation of assets.

# Exhibit 9-1
## BALANCE OF ENERGY PURCHASES AND SALES
## CONSOLIDATED DISTRIBUTION SYSTEM

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES SUMMARY GWh** | | | | | | |
| 65,405 | 57,312 | 51,052 | Industry | 48,988 | 48,864 | 48,843 | 49,300 | 50,410 | 51,612 |
| 5,675 | 5,346 | 4,915 | Railways | 5,160 | 5,631 | 6,158 | 6,800 | 6,940 | 7,092 |
| 9,386 | 8,218 | 9,821 | Commercial | 9,192 | 9,676 | 10,206 | 10,871 | 11,201 | 11,556 |
| 8,633 | 8,124 | 8,394 | Agriculture | 8,422 | 8,865 | 9,351 | 9,960 | 10,262 | 10,587 |
| 20,267 | 22,183 | 20,829 | Residential | 21,937 | 23,091 | 24,356 | 25,943 | 26,731 | 27,578 |
| 28,900 | 30,307 | 29,223 | Sub-total - Agricult & Resid'l | 30,359 | 31,956 | 33,707 | 35,903 | 36,993 | 38,165 |
| 1,506 | 1,325 | 1,372 | Street Lighting | 1,375 | 1,448 | 1,527 | 1,627 | 1,676 | 1,729 |
| 111,072 | 102,508 | 96,383 | **TOTAL ENERGY SALES** | 95,074 | 97,575 | 100,441 | 104,501 | 107,220 | 110,154 |
| | | | **AVERAGE TARIFF** | | | | | | |
| 0.0 | 241.1 | 341.7 | Industry | | | | | | |
| 0.0 | 264.7 | 352.6 | Railways | | | | | | |
| 0.0 | 340.6 | 502.1 | Commercial | | | | | | |
| 0.0 | 119.2 | 317.4 | Agriculture | | | | | | |
| 0.0 | 99.6 | 304.0 | Residential | | | | | | |
| 0.0 | 104.9 | 307.8 | Sub-total - Agricult & Resid'l | | | | | | |
| 0.0 | 506.5 | 741.3 | Street Lighting | | | | | | |
| 19.9 | 213.4 | 354.0 | **OVERALL AVERAGE TARIFF** | 542.1 | 542.1 | 785.0 | 785.0 | 795.0 | 805.0 |
| | | | **TOTAL SALES REVENUE** | | | | | | |
| | 13,815 | 17,443 | Industry | | | | | | |
| | 1,415 | 1,733 | Railways | | | | | | |
| | 2,799 | 4,931 | Commercial | | | | | | |
| | 969 | 2,664 | Agriculture | | | | | | |
| | 2,210 | 6,331 | Residential | | | | | | |
| | 3,179 | 8,995 | Sub-total - Agricult & Resid'l | | | | | | |
| | 671 | 1,017 | Street Lighting | | | | | | |
| 2,215 | 21,880 | 34,119 | **GRAND TOTAL SALES -- ELECTRICITY** | 51,540 | 52,895 | 78,846 | 82,033 | 85,240 | 88,674 |

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## Exhibit 9-2a
## INCOME STATEMENT – CONSOLIDATED DISTRIBUTION SYSTEM

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| 111,072 | 102,508 | 96,383 | Energy Sales -- GWh | 95,074 | 97,575 | 100,441 | 104,501 | 107,220 | 110,154 |
| 19.9 | 213.4 | 354.0 | Average Tariff -- Zl/kWh | 542.1 | 542.1 | 785.0 | 785.0 | 795.0 | 805.0 |
| 2,215 | 21,880 | 34,119 | Total Energy Sales Revenue | 51,540 | 52,895 | 78,846 | 82,033 | 85,240 | 88,674 |
| 16 | 332 | 676 | Other Revenues (Net) | 773 | 793 | 1,183 | 1,230 | 1,279 | 1,330 |
| 2,231 | 22,212 | 34,795 | Total Revenue | 52,313 | 53,689 | 80,029 | 83,264 | 86,518 | 90,004 |
| | | | Energy Costs | | | | | | |
| | | 130 | Own Thermal | | | | | | |
| | | 248 | Own Hydro | | | | | | |
| | | 50 | Auto producer | 58 | 58 | 58 | 58 | 58 | 58 |
| | | 7 | Small Hydro | | | | | | |
| 1,530 | 15,122 | 23,715 | PSE | 35,989 | 36,341 | 62,039 | 63,322 | 65,259 | 68,497 |
| 1,530 | 15,114 | 24,149 | Total Energy Costs | 36,047 | 36,399 | 62,097 | 63,380 | 65,317 | 68,556 |
| | | | Transmission and Customer Service | | | | | | |
| 25 | 216 | 317 | Materials | | | | | | |
| 137 | 1,422 | 1,593 | Repairs | | | | | | |
| 243 | 1,275 | 2,090 | Salaries and Payroll Taxes | | | | | | |
| 61 | 1,192 | 3,418 | Amortization | | | | | | |
| 115 | 688 | 299 | Administration Overhhead | | | | | | |
| | | | Other Costs | | | | | | |
| 581 | 4,793 | 7,717 | TOTAL FIXED OPERATING COSTS | 0 | 0 | 0 | 0 | 0 | 0 |
| | | | Less: High Voltage Network Costs | | | | | | |
| | 4 | 9 | Materials | | | | | | |
| | 44 | 54 | Repairs | | | | | | |
| | 26 | 39 | Salaries and Taxes | | | | | | |
| | 146 | 469 | Amortization | | | | | | |
| | 53 | 87 | Administration Overhhead | | | | | | |
| | 30 | 56 | Other Costs | | | | | | |
| | 303 | 714 | Total High Voltage Network Costs | 0 | 0 | 0 | 0 | 0 | 0 |

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## Exhibit 9–2a
## INCOME STATEMENT – CONSOLIDATED DISTRIBUTION SYSTEM

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | Net Distribution Network Costs | | | | | | |
| | 212 | 306 | Materials | 425 | 425 | 425 | 425 | 425 | 425 |
| | 1,378 | 1,539 | Repairs | 2,123 | 2,123 | 2,123 | 2,123 | 2,123 | 2,123 |
| | 1,249 | 2,051 | Salaries and Taxes | 1,732 | 1,732 | 1,732 | 1,732 | 1,732 | 1,732 |
| | 1,047 | 2,949 | Amortization | 12,239 | 12,239 | 12,384 | 12,703 | 13,237 | 14,017 |
| | 835 | 212 | Administration Overhhead | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 |
| | (30) | (56) | Other Costs | (78) | (78) | (78) | (78) | (78) | (78) |
| | 4,490 | 7,002 | Total Distribution Costs @1992 | 17,832 | 17,832 | 17,977 | 18,297 | 18,830 | 19,610 |
| | | | Plus: Inflation | 0 | 0 | 0 | 0 | 0 | 0 |
| | | | Total Distribution Costs | 17,832 | 17,832 | 17,977 | 18,297 | 18,830 | 19,610 |
| 2,111 | 18,907 | 31,866 | TOTAL COSTS | 53,679 | 54,232 | 60,075 | 61,677 | 64,148 | 68,166 |
| 118 | 2,305 | 2,929 | OPERATING INCOME | (1,567) | (543) | (46) | 1,587 | 2,371 | 1,838 |
| 21 | 347 | 1,376 | OTHER INCOME | 1,581 | 1,597 | 2,724 | 2,780 | 2,865 | 3,007 |
| 2 | 5 | 260 | Interest Expense | (192) | (554) | (711) | (1,064) | (1,041) | (1,064) |
| 139 | 2,647 | 4,044 | INCOME BEFORE TAX | 207 | 1,608 | 3,389 | 5,430 | 6,277 | 5,908 |
| 39 | 1,716 | 2,874 | Less: Income & Corporate Tax | 142 | 643 | 1,355 | 2,172 | 2,511 | 2,363 |
| 100 | 931 | 1,170 | NET INCOME | 65 | 965 | 2,033 | 3,258 | 3,766 | 3,545 |

Billions Zloty at Base Year Prices

Case: DISCOBAS\dscr011

RCG/HAGLER, BAILLY, Inc.

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## Exhibit 9-2b
## BALANCE SHEET – CONSOLIDATED DISTRIBUTION SYSTEM

| PRO-FORMA | ACTUAL | ACTUAL | POLISH DISTRIBUTION COMPANIES | ESTIMATE | FORECAST | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1989 | 1990 | 1991 | Year End -- December 31 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 |
| | | | **ASSETS** | | | | | | |
| | 1,116 | 1,226 | Cash | 1,692 | 1,692 | 1,692 | 1,692 | 1,692 | 1,692 |
| | 895 | 3,716 | Accounts Receivable | 8,719 | 8,948 | 13,338 | 13,877 | 14,420 | 15,001 |
| | 318 | 532 | Inventories | 735 | 735 | 735 | 735 | 735 | 735 |
| 0 | 2,329 | 5,474 | Total Current Assets | 11,145 | 11,375 | 15,765 | 16,304 | 16,846 | 17,427 |
| | | 66,711 | | | | | | | |
| | | | Gross Fixed Assets: | | | | | | |
| | | 6,903 | Transmission (>110kv)& S/stations | | | | | | |
| | | 44,206 | Distribution Lines | | | | | | |
| | | 14,803 | Substations | | | | | | |
| | | 4,930 | Other Fixed & Tangible Assets | | | | | | |
| | 65,818 | 70,842 | Gross Fixed & Tangible Assets | 244,775 | 247,676 | 254,063 | 264,737 | 280,337 | 296,564 |
| | 33,859 | 36,976 | Less: Acc. Depreciation | 140,000 | 152,239 | 164,623 | 177,326 | 190,563 | 204,579 |
| | 31,959 | 33,866 | Net Fixed & Tangible Assets | 104,775 | 95,439 | 89,440 | 87,412 | 89,774 | 91,985 |
| | 1,190 | 2,903 | Capital Work-in-Progress | 2,903 | 6,385 | 10,674 | 15,600 | 16,227 | 16,389 |
| | 6 | 30 | Goodwill | | | | | | |
| 0 | 34,927 | 42,272 | TOTAL ASSETS EMPLOYED | 118,823 | 113,199 | 115,880 | 119,315 | 122,848 | 125,801 |
| | | | **LIABILITIES** | | | | | | |
| | 891 | 2,671 | Accounts Payable | | | | | | |
| | 633 | 3,799 | Other Liabilities | | | | | | |
| | | 0 | Cash Deficiency (Surplus) | (3,492) | (10,081) | (9,434) | (9,256) | (9,489) | (10,081) |
| 0 | 1,784 | 6,470 | Total Current Liabilities | (3,492) | (10,081) | (9,434) | (9,256) | (9,489) | (10,081) |
| | 575 | 1,309 | Long Term Debt | 1,309 | 1,309 | 1,309 | 1,309 | 1,309 | 1,309 |
| | | | Equity Balance: | | | | | | |
| | 31,645 | 32,578 | Assumed Opening Position | 32,578 | 32,578 | 32,578 | 32,578 | 32,578 | 32,578 |
| | | | Reserve for Asset Revaluation | 86,448 | 86,448 | 86,448 | 86,448 | 86,448 | 86,448 |
| | | 923 | Retained Earnings -- Prior Years | 1,915 | 1,979 | 2,944 | 4,978 | 8,236 | 12,002 |
| | 923 | 991 | Current Year's Net Income | 65 | 965 | 2,033 | 3,258 | 3,766 | 3,545 |
| | 32,568 | 34,492 | Total Equity | 121,005 | 121,970 | 124,004 | 127,262 | 131,028 | 134,573 |
| | 34,927 | 42,272 | TOTAL LIABILITIES & EQUITY | 118,823 | 113,199 | 115,880 | 119,315 | 122,848 | 125,801 |

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## Exhibit 9-2c
## OPERATING AND FINANCIAL RATIOS – CONSOLIDATED DISTRIBUTION SYSTEM
### Criterion = Zero Debt Increase

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| 19.942 | 213.444 | 353.994 | Average Sales Tariff -- Zl/ kWh | 542.100 | 542.100 | 785.000 | 785.000 | 795.000 | 805.000 |
| | 135.258 | 221.677 | Average Purchase Cost -- Zl/ kWh | 339.071 | 336.295 | 561.492 | 555.559 | 557.590 | 569.586 |
| | -7.7% | -6.0% | Annual Sales Growth (kWh) -- % | -1.4% | 2.6% | 2.9% | 4.0% | 2.6% | 2.7% |
| | 887.8% | 55.9% | Annual Sales Growth (Zl) -- % | 51.1% | 2.6% | 49.1% | 4.0% | 3.9% | 4.0% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 8.3% | 11.6% | Distribution Losses -- % | 10.6% | 9.9% | 9.2% | 8.4% | 8.5% | 8.5% |
| | 63.4% | 62.6% | Energy Purchase/ Sales -- % | 62.5% | 62.0% | 71.5% | 70.8% | 70.1% | 70.8% |
| 5.4% | 10.4% | 8.4% | Operating Income/ Sales -- % | -3.0% | -1.0% | -0.1% | 1.9% | 2.7% | 2.0% |
| | 3.4% | 3.9% | Operating Income/ Net Assets -- % | -2.1% | -0.5% | -0.0% | 1.5% | 2.3% | 1.7% |
| | 2.9% | 3.4% | Net Income after Tax/ Equity -- % | 0.1% | 0.8% | 1.6% | 2.6% | 2.9% | 2.6% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 1.3 | 0.8 | Current Ratio | -3.2 | -1.1 | -1.7 | -1.8 | -1.8 | -1.7 |
| | 7.2% | 22.6% | Total Debt/ Equity -- % | 1.8% | 7.2% | 6.6% | 6.2% | -6.2% | -6.5% |
| | | | Self-Financing Ratio -- % | | 232.2% | 132.4% | 112.7% | 105.8% | 107.9% |

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# Exhibit 9-2d
## OPERATING AND FINANCIAL RATIOS – CONSOLIDATED DISTRIBUTION SYSTEM
### Criterion = 6% Return on Assets

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| 19.942 | 213.444 | 353.994 | Average Sales Tariff -- Zl/ kWh | 542.100 | 542.100 | 847.000 | 829.000 | 831.000 | 846.000 |
| | 135.258 | 221.677 | Average Purchase Cost -- Zl/ kWh | 339.071 | 336.295 | 561.492 | 555.559 | 557.590 | 569.588 |
| | -7.7% | -6.0% | Annual Sales Growth (kWh) -- % | -1.4% | 2.6% | 2.9% | 4.0% | 2.6% | 2.7% |
| | 887.8% | 55.9% | Annual Sales Growth (Zl) -- % | 51.1% | 2.6% | 60.8% | 1.8% | 2.8% | 4.6% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 8.3% | 11.6% | Distribution Losses -- % | 10.6% | 9.9% | 9.2% | 8.4% | 8.5% | 8.5% |
| | 63.4% | 62.6% | Energy Purchase/ Sales -- % | 62.5% | 62.0% | 66.3% | 67.0% | 67.1% | 67.3% |
| 5.4% | 10.4% | 8.4% | Operating Income/ Sales -- % | -3.0% | -1.0% | 7.3% | 7.1% | 7.0% | 6.8% |
| | 3.4% | 3.9% | Operating Income/ Net Assets -- % | -2.1% | -0.5% | 6.0% | 6.0% | 6.0% | 6.0% |
| | 2.9% | 3.4% | Net Income after Tax/ Equity -- % | 0.1% | 0.8% | 4.6% | 4.7% | 4.6% | 4.7% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 1.3 | 0.8 | Current Ratio | -3.2 | -1.1 | -1.4 | -1.1 | -0.9 | -0.8 |
| | 7.2% | 22.6% | Total Debt/ Equity -- % | -1.8% | -7.2% | -8.6% | -10.5% | -12.2% | -14.2% |
| | | | Self-Financing Ratio -- % | | 232.2% | 168.1% | 133.9% | 122.8% | 128.5% |

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# Exhibit 9-2e
## OPERATING AND FINANCIAL RATIOS – CONSOLIDATED DISTRIBUTION SYSTEM
### Criterion = 100% Self Financing

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| 19 942 | 213.444 | 353.994 | Average Sales Tariff -- Zl/ kWh | 542.100 | 542.100 | 739.000 | 760 000 | 786.000 | 792.000 |
| | 135.258 | 221.677 | Average Purchase Cost -- Zl/ kWh | 339.071 | 336.295 | 561.492 | 555.559 | 557.590 | 569 588 |
| | -7.7% | -6.0% | Annual Sales Growth (kWh) -- % | -1.4% | 2 6% | 2.9% | 4.0% | 2.6% | 2 7% |
| | 887.6% | 55.9% | Annual Sales Growth (Zl) -- % | 51.1% | 2.6% | 40 3% | 7 0% | 6.1% | 3.5% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 8.3% | 11.6% | Distribution Losses - % | 10.6% | 9 9% | 9 2% | 8 4% | 8.5% | 8 5% |
| | 63.4% | 62.6% | Energy Purchase/ Sales -- % | 62 5% | 62 0% | 76 0% | 73 1% | 70 9% | 71 9% |
| 5 4% | 10 4% | 8.4% | Operating Income/ Sales -- % | -3 0% | 1 0% | 6 3% | 1 3% | 1 6% | 0 4% |
| | 3.4% | 3.9% | Operating Income/ Net Assets -- % | -2 1% | 0 5% | -4 6% | 1 0% | 1 3% | 0 4% |
| | 2.9% | 3.4% | Net Income after Tax/ Equity -- % | 0 1% | 0 8% | -1 2% | 1 2% | 2.3% | 1 8% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 1.3 | 0 8 | Current Ratio | -3 2 | 1 1 | 2 2 | 3 6 | -4 7 | -5 8 |
| | 7.2% | 22.6% | Total Debt/ Equity -- % | 1 8% | 7 2% | -4 5% | -2 6% | -1.8% | -1 3% |
| | | | Self-Financing Ratio -- % | | 232 2% | 100 4% | 100 3% | 100.4% | 100 1% |

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## 9.5 SUMMARY OF RESULTS OF THE UNCONSTRAINED FINANCIAL ANALYSIS OF THE CONSOLIDATED SYSTEM

Exhibit 9-2f shows a summary of the results of the financial revenue requirements analyses for the consolidated generation, transmission and distribution system. For the distribution system, the most strongly recommended financial criterion was used: that is, no increase in overall debt.

## 9.6 CASE STUDIES FOR DISTRIBUTION COMPANIES

In order to study the effect of uniform bulk sales tariffs on individual distribution utilities, the financial outlook of three companies was examined. The financial and operating ratios for the distribution company Bialystok are shown in Exhibit 9-3a,b, and c corresponding to the three financial criteria discussed above for the consolidated system. The same information is shown for the Gliwice Distribution Company in Exhibit 9-4 and for the Warsaw Distribution Company in Exhibit 9-5.

The resulting 1994 revenue requirements for each company and according to the different criteria are shown in Exhibit 9-6. Because the capital investment forecasts for each of these companies were not available, they were estimated on a basis that is not directly comparable to the forecast available for the consolidated distribution system. Thus, the results for these companies are only valid to establish relative differences among them and not in relation to the entire system. Nevertheless, the following conclusions are possible:

- The spreads among the average retail tariffs of these companies are 60.0 percent, 50.2 percent, and 48.92 percent corresponding to criteria A, B and C above.

- As might be expected, tariffs for Bialystok (rural area) are consistently the highest while tariffs for the heaviest industrial area Gliwice are consistently the lowest.

EXHIBIT 9-2F

SUMMARY OF REVENUE
REQUIREMENTS THROUGH THE SYSTEM

| | 1992 | 1994 | 1995 | 1996 | 1997 | FINANCIAL CRITERION |
|---|---|---|---|---|---|---|
| GENERATING COMPANIES | 300.296 | 488.951 | 487.195 | 490.566 | 504.206 | 6% Return on Net Assets |
| PPGC | 336.716 | 563.000 | 557.000 | 559.000 | 571.000 | 6% Return on Net Assets |
| DISTRIBUTION COMPANIES Criterion A | 542.100 | 785.000 | 785.000 | 795.000 | 805.000 | No increase in Overall Borrowing 1993-1997 |
| DISTRIBUTION COMPANIES Criterion C | 542.100 | 739.000 | 760.000 | 786.000 | 792.000 | 100% Self Financing Ratio |

## Exhibit 9-3a
## OPERATING AND FINANCIAL RATIOS – BIALYSTOK DISTRIBUTION COMPANY
### Criterion = Zero Debt Increase

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| 0.000 | 211.112 | 393.061 | Average Sales Tariff -- Zl/ kWh | 542.100 | 542.100 | 1245.000 | 1245.000 | 1245.000 | 1245.000 |
| | 104.089 | 181.800 | Average Purchase Cost -- Zl/ kWh | 339.071 | 336.295 | 563.000 | 557.000 | 559.000 | 571.000 |
| | | -3.7% | Annual Sales Growth (kWh) -- % | 15.8% | 3.5% | 3.5% | 5.2% | 2.8% | 2.9% |
| | 931.7% | 79.3% | Annual Sales Growth (Zl) -- % | 59.7% | 3.5% | 137.6% | 5.2% | 2.8% | 2.9% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 1.2% | 19.6% | Distribution Losses - % | 9.8% | 9.0% | 8.3% | 7.5% | 7.5% | 7.5% |
| | 49.3% | 46.2% | Energy Purchase/ Sales -- % | 62.5% | 62.0% | 45.2% | 44.7% | 44.9% | 45.9% |
| 8.7% | 10.7% | 11.0% | Operating Income/ Sales -- % | 6.1% | -20.9% | 28.4% | 29.4% | 28.9% | 27.2% |
| | 10.2% | 8.8% | Operating Income/ Net Assets -- % | 1.6% | -3.3% | 10.9% | 11.7% | 11.4% | 10.8% |
| | 1.6% | 5.7% | Net Income after Tax/ Equity -- % | 1.4% | -2.9% | 6.8% | 7.2% | 7.0% | 6.7% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 1.0 | 0.8 | Current Ratio | -0.4 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| | 8.8% | 17.3% | Total Debt/ Equity | -1.5% | 8.2% | 8.2% | 9.7% | 8.2% | 7.3% |
| | | | Self Financing Ratio -- % | 100.6% | 56.9% | 142.1% | 152.2% | 151.7% | 252.3% |

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## Exhibit 9-3b
## OPERATING AND FINANCIAL RATIOS - BIALYSTOK DISTRIBUTION COMPANY
### Criterion = 6% Return on Assets

| PRO FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| 0.000 | 211.112 | 393.081 | Average Sales Tariff -- Zl/kWh | 542.100 | 542.100 | 1,086.000 | 1,068.000 | 1,073.000 | 1,093.000 |
| | 104.089 | 181.800 | Average Purchase Cost -- Zl/ kWh | 339.071 | 336.295 | 563.000 | 557.000 | 559.000 | 571.000 |
| | | -3.7% | Annual Sales Growth (kWh) -- % | 15.8% | 3.5% | 3.5% | 5.2% | 2.8% | 2.9% |
| | 931.7% | 79.3% | Annual Sales Growth (Zl) -- % | 59.7% | 3.5% | 107.3% | 3.5% | 3.3% | 4.8% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 1.2% | 19.6% | Distribution Losses - % | 9.8% | 9.0% | 8.3% | 7.5% | 7.5% | 7.5% |
| | 49.3% | 46.2% | Energy Purchase/ Sales -- % | 62.5% | 62.0% | 51.8% | 52.2% | 52.1% | 52.2% |
| 8.7% | 10.7% | 11.0% | Operating Income/ Sales -- % | 6.1% | -20.9% | 17.9% | 17.7% | 17.5% | 17.1% |
| | 10.2% | 8.8% | Operating Income/ Net Assets -- % | 1.6% | -3.3% | 6.0% | 6.0% | 6.0% | 6.0% |
| | 1.6% | 5.7% | Net Income after Tax/ Equity -- % | 1.4% | 2.9% | 4.0% | 4.1% | 4.2% | 4.3% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 1.0 | 0.8 | Current Ratio | -0.4 | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 |
| | 8.8% | 17.3% | Total Debt/ Equity | 1.5% | 8.2% | 11.4% | 16.8% | 19.1% | 21.6% |
| | | | Self Financing Ratio -- % | 100.6% | 56.9% | 109.5% | 114.3% | 115.1% | 196.2% |

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## Exhibit 9-4a
## OPERATING AND FINANCIAL RATIOS – GLIWICE DISTRIBUTION COMPANY
### Criterion = Zero Debt Increase

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| 0.000 | 204.291 | 322.284 | Average Sales Tariff -- Zl/ kWh | 542.100 | 542.100 | 776.940 | 768.660 | 771.420 | 787 980 |
| | 164.983 | 247.583 | Average Purchase Cost -- Zl/ kWh | 339.071 | 336.295 | 563.000 | 557 000 | 559.000 | 571 000 |
| | | -8.0% | Annual Sales Growth (kWh) -- % | -0.1% | 1 3% | 1.6% | 2 7% | 2.5% | 2 6% |
| | 855.1% | 45.1% | Annual Sales Growth (Zl) -- % | 66.1% | 1 3% | 45 6% | 1 6% | 2.8% | 4 8% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 3.8% | 7.9% | Distribution Losses - % | 9.8% | 9 0% | 8 3% | 7 5% | 7.5% | 7 5% |
| | 80.8% | 76 8% | Energy Purchase/ Sales -- % | 62.5% | 62 0% | 72 5% | 72 5% | 72 5% | 72 5% |
| 2 5% | 7.8% | 6 1% | Operating Income/ Sales -- % | 21.4% | 16 1% | 10 1% | 10 6% | 10.6% | 10 7% |
| | 5.5% | 5 5% | Operating Income/ Net Assets -- % | 30.2% | 30 4% | 13 1% | 13 6% | 12.7% | 12 7% |
| | 4.5% | 2.6% | Net Income after Tax/ Equity -- % | 6.6% | 4.8% | 7 9% | 7 8% | 7.4% | 7 3% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 0.9 | 0.7 | Current Ratio | 1 5 | 1 4 | 1 4 | 1 4 | 1 5 | 1 6 |
| | 11.6% | 33.0% | Total Debt/ Equity | 13 1% | 13 6% | 17 9% | 16 1% | 14.4% | 13 1% |
| | | | Self Financing Ratio -- % | 319.6% | 235 2% | 181 8% | 172 7% | 161.5% | 252 4% |

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## Exhibit 9–3c
## OPERATING AND FINANCIAL RATIOS – BIALYSTOK DISTRIBUTION COMPANY
### Criterion = 100% Self Financing Ratio

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| 0.000 | 211.112 | 393.061 | Average Sales Tariff -- Zl/kWh | 542.100 | 542.100 | 1,042.000 | 1,005.000 | 1,005.000 | 825.000 |
| | 104.069 | 181.800 | Average Purchase Cost -- Zl/kWh | 339.071 | 336.295 | 563.000 | 557.000 | 559.000 | 571.000 |
| | | -3.7% | Annual Sales Growth (kWh) -- % | 15.8% | 3.5% | 3.5% | 5.2% | 2.8% | 2.9% |
| | 931.7% | 79.3% | Annual Sales Growth (Zl) -- % | 59.7% | 3.5% | 96.9% | 1.5% | 2.8% | 15.5% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 1.2% | 19.6% | Distribution Losses - % | 9.8% | 9.0% | 8.3% | 7.5% | 7.5% | 7.5% |
| | 49.3% | 46.2% | Energy Purchase/ Sales -- % | 62.5% | 62.0% | 54.0% | 55.4% | 55.6% | 69.2% |
| 8.7% | 10.7% | 11.0% | Operating Income/ Sales -- % | 6.1% | -20.9% | 14.5% | 12.6% | 11.9% | 9.8% |
| | 10.2% | 8.8% | Operating Income/ Net Assets -- % | 1.6% | -3.3% | 4.6% | 4.0% | 3.6% | 2.6% |
| | 1.6% | 5.7% | Net Income after Tax/ Equity -- % | 1.4% | -2.9% | 3.2% | 2.9% | 2.9% | 1.5% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 1.0 | 0.8 | Current Ratio | -0.4 | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 |
| | 6.6% | 17.3% | Total Debt/ Equity | -1.5% | 8.2% | 12.4% | 19.3% | 23.4% | 34.0% |
| | | | Self Financing Ratio -- % | 100.6% | 56.9% | 100.5% | 100.7% | 100.7% | 102.8% |

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## Exhibit 9-4b
## OPERATING AND FINANCIAL RATIOS – GLIWICE DISTRIBUTION COMPANY
### Criterion = 6% Return on Assets

| PRO-FORMA 1988 | ACTUAL 1989 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| 0.000 | 204.291 | 322.284 | Average Sales Tariff -- Zl/kWh | 542.100 | 542.100 | 735.000 | 723.000 | 728.000 | 743.000 |
| | 164.983 | 247.583 | Average Purchase Cost -- Zl/ kWh | 339.071 | 336.295 | 563.000 | 557.000 | 559.000 | 571.000 |
| | | -8.0% | Annual Sales Growth (kWh) -- % | -0.1% | 1.3% | 1.6% | 2.7% | 2.5% | 2.6% |
| | 855.1% | 45.1% | Annual Sales Growth (Zl) -- % | 68.1% | 1.3% | 37.8% | 1.0% | 3.2% | 4.7% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 3.8% | 7.9% | Distribution Losses - % | 9.8% | 9.0% | 8.3% | 7.5% | 7.5% | 7.5% |
| | 80.8% | 76.8% | Energy Purchase/ Sales -- % | 62.5% | 62.0% | 76.6% | 77.0% | 76.8% | 76.9% |
| 2.5% | 7.8% | 6.1% | Operating Income/ Sales -- % | 21.4% | 16.1% | 5.0% | 5.0% | 5.3% | 5.3% |
| | 5.5% | 5.5% | Operating Income/ Net Assets -- % | 30.2% | 30.4% | 6.1% | 6.0% | 6.1% | 6.0% |
| | 4.5% | 2.6% | Net Income after Tax/ Equity -- % | 6.6% | 4.8% | 3.9% | 3.8% | 3.9% | 4.0% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 0.9 | 0.7 | Current Ratio | 1.5 | 1.4 | 1.1 | 1.0 | 0.8 | 0.8 |
| | 11.6% | 33.0% | Total Debt/ Equity | 13.1% | 13.6% | 21.8% | 25.1% | 28.0% | 31.0% |
| | | | Self Financing Ratio -- % | 319.6% | 235.2% | 135.5% | 126.2% | 120.6% | 188.3% |

Case: DISCOBAS\gliw002

RCG/HAGLER, BAILLY, Inc.
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## Exhibit 9-5a
## OPERATING AND FINANCIAL RATIOS – WARSAWA DISTRIBUTION COMPANY
### Criterion = Zero Debt Increase

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| | 228.113 | 378 867 | Average Sales Tariff -- Zl/ kWh | 542.100 | 542.100 | 906.430 | 896.770 | 899.990 | 919.310 |
| | 145.019 | 238 353 | Average Purchase Cost -- Zl/ kWh | 339.071 | 336.295 | 563.000 | 557.000 | 559 000 | 571 000 |
| | | -9 6% | Annual Sales Growth (kWh) -- % | 9.3% | 3.3% | 3.6% | 4.7% | 2.7% | 2 8% |
| | | 50 2% | Annual Sales Growth (Zl) -- % | 56.3% | 3.3% | 73.3% | 3.6% | 3 0% | 5 0% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 9.9% | 13 2% | Distribution Losses - % | 9.8% | 9.0% | 8.3% | 7.5% | 7.5% | 7 5% |
| | 63 6% | 62 9% | Energy Purchase/ Sales -- % | 62.5% | 62.0% | 62.1% | 62.1% | 62 1% | 62 1% |
| 4 9% | 8 5% | 3 6% | Operating Income/ Sales -- % | 9.2% | 1.9% | 14.9% | 15.6% | 15 6% | 15 8% |
| 43.1% | 16 7% | 4 7% | Operating Income/ Net Assets -- % | 9.6% | 1.5% | 17.8% | 16.9% | 15.8% | 15 5% |
| | 3.0% | 0.5% | Net Income after Tax/ Equity -- % | 2.4% | 0.5% | 11.3% | 10.9% | 10.1% | 9 7% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 1.1 | 0.7 | Current Ratio | 1.2 | 0.7 | 0.8 | 0.8 | 0 9 | 1 0 |
| | 8 9% | 34.5% | Total Debt/ Equity | 13.6% | 24.5% | 30.3% | 28.6% | 23 4% | 19 1% |
| | | | Self Financing Ratio -- % | 124.3% | 114.4% | 143.7% | 152.4% | 155 6% | 174.7% |

Case: DISCOBAS\warw001

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## Exhibit 9-5b
## OPERATING AND FINANCIAL RATIOS – WARSAWA DISTRIBUTION COMPANY
### Criterion = 6% Return on Assets

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| | 228.113 | 378.867 | Average Sales Tariff -- Zl/ kWh | 542.100 | 542.100 | 817.000 | 807.000 | 813.000 | 830.000 |
| | 145.019 | 236.353 | Average Purchase Cost -- Zl/ kWh | 339.071 | 336.295 | 563.000 | 557.000 | 559.000 | 571.000 |
| | | -9.6% | Annual Sales Growth (kWh) -- % | 9.3% | 3.3% | 3.6% | 4.7% | 2.7% | 2.8% |
| | | 50.2% | Annual Sales Growth (Zl) -- % | 56.3% | 3.3% | 56.2% | 3.4% | 3.4% | 5.0% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 9.9% | 13.2% | Distribution Losses - % | 9.8% | 9.0% | 8.3% | 7.5% | 7.5% | 7.5% |
| | 63.6% | 62.9% | Energy Purchase/ Sales -- % | 62.5% | 62.0% | 68.9% | 69.0% | 68.8% | 68.8% |
| 4.9% | 8.5% | 3.6% | Operating Income/ Sales -- % | 9.2% | 1.9% | 5.6% | 6.2% | 6.5% | 6.7% |
| 43.1% | 16.7% | 4.7% | Operating Income/ Net Assets -- % | 9.6% | 1.5% | 6.1% | 6.1% | 6.1% | 6.1% |
| | 3.0% | 0.5% | Net Income after Tax/ Equity -- % | 2.4% | 0.5% | 4.1% | 4.5% | 4.7% | 4.8% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 1.1 | 0.7 | Current Ratio | 1.2 | 0.7 | 0.6 | 0.5 | 0.5 | 0.4 |
| | 8.9% | 34.5% | Total Debt/ Equity | 13.6% | 24.5% | 38.6% | 46.7% | 49.2% | 51.9% |
| | | | Self Financing Ratio -- % | 124.3% | 114.4% | 93.6% | 100.4% | 105.1% | 118.8% |

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## Exhibit 9–5c
## OPERATING AND FINANCIAL RATIOS – WARSAWA DISTRIBUTION COMPANY
### Criterion = 100% Self Financing Ratio

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| | 228.113 | 378.867 | Average Sales Tariff -- Zl/ kWh | 542.100 | 542.100 | 829.000 | 807.000 | 805.000 | 800.000 |
| | 145.019 | 238.353 | Average Purchase Cost -- Zl/ kWh | 339.071 | 336.295 | 563.000 | 557.000 | 559.000 | 571.000 |
| | | -9.6% | Annual Sales Growth (kWh) -- % | 9.3% | 3.3% | 3.6% | 4.7% | 2.7% | 2.6% |
| | | 50.2% | Annual Sales Growth (Zl) -- % | 56.3% | 3.3% | 58.5% | 1.9% | 2.4% | 2.2% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 9.9% | 13.2% | Distribution Losses - % | 9.8% | 9.0% | 8.3% | 7.5% | 7.5% | 7.5% |
| | 63.6% | 62.9% | Energy Purchase/ Sales -- % | 62.5% | 62.0% | 67.9% | 69.0% | 69.4% | 71.4% |
| 4.9% | 8.5% | 3.6% | Operating Income/ Sales -- % | 9.2% | 1.9% | 7.0% | 6.2% | 5.6% | 3.2% |
| 43.1% | 16.7% | 4.7% | Operating Income/ Net Assets -- % | 9.6% | 1.5% | 7.7% | 6.1% | 5.2% | 2.8% |
| | 3.0% | 0.5% | Net Income after Tax/ Equity -- % | 2.4% | 0.5% | 5.1% | 4.4% | 4.0% | 2.3% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 1.1 | 0.7 | Current Ratio | 1.2 | 0.7 | 0.6 | 0.5 | 0.5 | 0.4 |
| | 8.9% | 34.5% | Total Debt/ Equity | 13.6% | 24.5% | 37.4% | 45.2% | 48.6% | 54.8% |
| | | | Self Financing Ratio -- % | 124.3% | 114.4% | 100.3% | 100.4% | 100.5% | 100.0% |

Case: DISCOBAS\warsr003

RCG/HAGLER, BAILLY, Inc.
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EXHIBIT 9-6

REVENUE REQUIREMENTS OF THREE
DISTRIBUTION COMPANIES (ZI/kWh)

| DISTRIBUTION COMPANY | FINANCIAL CRITERION | | |
|---|---|---|---|
| | A<br>ZERO DEBT INCREASE | B<br>6% RETURN | C<br>100% SELF FINANCING |
| BIALYSTOK | 1245.0 | 1086.0 | 1042.0 |
| GLIWICE | 776.9 | 735.0 | 703.0 |
| WARSAW | 906.4 | 817.0 | 829.0 |

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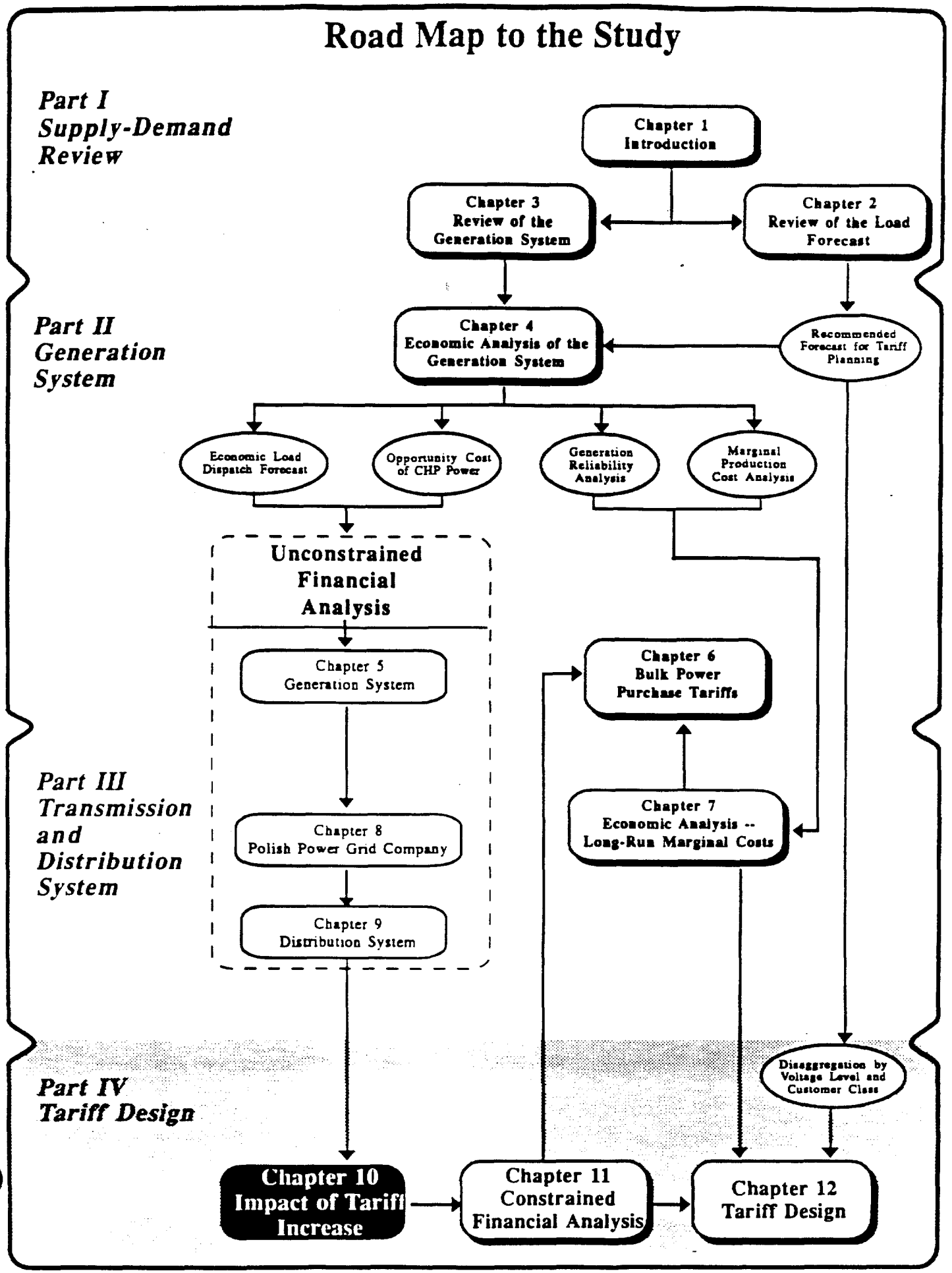
# Road Map to the Study

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# CHAPTER 10: IMPACT OF TARIFF INCREASES

This chapter assesses the impact of electricity tariff increases on Poland's end-users in order to adjust from current levels to full cost-based pricing. If the payment of new tariffs for electricity were extremely damaging to economic output or to the welfare of households, it might be desirable to design tariff phase-in periods, continued subsidies, or other mitigating measures.

This chapter focuses primarily on Polish industry and households, although agriculture and transportation are also discussed. For several reasons, it is not possible to rely fully on the information that is currently available on these end-users. First, where data exist, they are poor and may not reflect the values that are of most interest. Thus, data on past expenditures usually do not reflect the amounts spent now. Second, all end-users are experiencing markets in great disequilibrium. Even if precise data were available on variables of interest, it is likely that those values will change rapidly in the near future. Third, abrupt changes in the Polish incentive system imply significant changes in consumer and productive behavior over the relatively short run. Again, precise data on the current situation may not reveal much about the near future.

As a result of these conditions, we used empirical data where possible, and made judgments where good data were not available. For each end-user, we attempted to determine the amounts of money that are likely to be spent on electricity now. We then asked whether it would make a difference if tariffs were much higher. Polish decision-makers must ultimately judge whether or not the differences identified are significant in the Polish context.

## 10.1 THE IMPACTS ON INDUSTRY

A number of factors complicate the analysis of the impact of tariff increases on Poland's industries. First, the historical data available on Polish industry reflect many factors that were arbitrarily determined by state planners. Second, the disequilibrium faced by Polish industry now is so overpowering that it is difficult to predict what cost/price structures will be when "normal" conditions return. Third, prior to 1990, internal incentives for Polish industry were perverse, and in many cases, cost reductions resulted in reduced profit.[1]

Also, because electricity shortages were common, managers would take steps to reduce the potential damage to production that results from input shortages. If they incurred extra costs

[1] For an elaboration on the incentives embedded in socialized industry in Poland, see Kharas (1991).

to avoid shortages, they protected their ability to meet production targets and were rewarded with increased profits. In addition, it was common to contract for much more capacity than was actually needed (however, capacity was seldom drawn upon). Therefore, in calculating the cost of electricity to an enterprise, the cost per kWh may appear to be very high. This is not necessarily due to having used a great deal of energy, but to spreading the capacity charge over the energy that was used. A more rational contract for capacity would have shown reduced energy costs even if the amount of energy, production and all prices (including the prices of demand and energy) had remained the same.

Last, there were no standard electricity rates prior to 1990. Firms had their own individual rates, even if they operated under circumstances similar to those of other firms in the same industry.[2] Similar problems with other inputs make most cost/price data prior to 1991 irrelevant.

Since 1990, Polish industry has been in disequilibrium, making it difficult to determine "normal" cost/price relationships. Some of the dimensions of the disequilibrium include:

- Many industries, particularly heavy industry, are still state-owned. Many are still affected by state decisions, subsidies, financing, etc. Even those facing privatization do not yet have firmly established operating rules, nor are their managers operating under private incentives. Furthermore, industry lags other sectors in privatization. As of September 1992, private employment was 58 percent of total employment and some sectors, such as retail businesses, were over 80 percent private. Meanwhile, only 24 percent of industrial output was from private industry.

- Proper revaluation of industrial assets has not been completed. Thus, actual capital costs cannot be determined.

- International trade has been liberalized, and many firms are responding to international prices for the first time. However, most are only beginning to adjust their production to compete in freer markets and full adjustment will take time.

[2] To illustrate the range of electricity rates facing Polish industry, consider the average cost per kWh, as experienced in 1990-91, as reported by GUS, *Fuels and Energy Statistics* (October 1992). Table 2(67) reports the costs per kWh for 22 industries. The average cost was 441 Zl/kWh, but the standard deviation was 83 Zl. Therefore, 95 percent of industrial electrical energy costs would have fallen in the 293 Zl to 547 Zl range.

- For political reasons, firms that are suffering losses have been kept operating to protect employment levels. Some firms have maintained employment by cutting work hours. Others maintain "over employment" by keeping more workers than are necessary for current production levels. Wages are kept under control by an "excess wage tax," which applies to all employment in public enterprises and government. In general, as production has been cut back, labor forces have been reduced by much less.

This last point probably affects the pattern of recorded electricity in production. If firms respond to reduced demand by cutting back production but not employment, then the use of resources that support employees may be reduced by less than output is reduced. Excess employment wastes not only labor, but it also wastes the resources that support labor. In the case of electricity, as the same number of employees go through a scaled-back or slowed-down set of activities to produce less output, the amount of electricity consumed is not likely to drop by as much as output. Electrical devices will still be operated simply to keep the excessive number of workers "working." Under these circumstances, it is likely that as output drops, the electricity input per unit of output increases.

Exhibit 10-1 illustrates this phenomenon using data for 23 industrial branches over the period 1987-1991. For each industry it shows kWh per million zlotys of value added, in constant 1990 zlotys. It also shows real value-added per employee for the same period. Using the above reasoning, as output slowed between 1987-89 and 1990-91, the ratio of kWh to value-added should rise, which in general it does. Furthermore, those industries where value-added per employee has fallen most are those that are suffering from the most "over employment." Thus, the kWh to value-added ratio should rise most where value-added per employee has fallen most, which also appears to be the case. For example, in coal mining and fuels production, the ratio has risen about 60 percent and 100 percent, respectively. At the same time, value-added per employee in coal (the most notorious case of maintaining employment despite demand conditions) has fallen by about 40 percent and in fuels by 60 percent. In industry branches where demand has held up (e.g., wood, construction materials) or where workers have been laid off (e.g., clothing) the kWh/value-added ratio has not risen.

This examination reveals three important points. First, what appears to be increasingly electricity-intensive industrial production probably is not. It is merely a reflection of unique conditions facing Polish industry. Second, the level of electricity intensity in Polish industry

# EXHIBIT 10-1

## ELECTRICITY AND EMPLOYMENT IN POLISH INDUSTRY

kWh/VA = kWh per million zlotys of valve added
VA/Empl. = Valve-added per employee, in million Zl.
All figures are in zlotys of 1990

| | 1987 | 1988 | 1989 | 1990 | 1991 |
|---|---|---|---|---|---|
| **INDUSTRY OVERALL** | | | | | |
| kWh/VA | 302 | 293 | 296 | 344 | 385 |
| VA/Empl. | na | na | na | na | na |
| **COAL** | | | | | |
| kWh/VA | 605 | 667 | 744 | 1070 | 1064 |
| VA/Empl. | 39.6 | 36.5 | 32.1 | 21.7 | 22.2 |
| **FUEL** | | | | | |
| kWh/VA | 84 | 89 | 98 | 155 | 181 |
| VA/Empl. | 589.2 | 566.4 | 543.0 | 315.1 | 228.8 |
| **ELECTRIC ENERGY** | | | | | |
| kWh/VA | 581 | 598 | 783 | 1076 | 1635 |
| VA/Empl. | 238.3 | 228.2 | 178.6 | 122.1 | 75.0 |
| **IRON & STEEL** | | | | | |
| kWh/VA | 366 | 393 | 438 | 454 | 566 |
| VA/Empl. | 172.6 | 165.0 | 146.9 | 140.7 | 95.4 |
| **NON FERROUS METALS** | | | | | |
| kWh/VA | 288 | 283 | 305 | 425 | 817 |
| VA/Empl. | 305.2 | 320.0 | 297.5 | 199.3 | 107.3 |
| **METALS** | | | | | |
| KwH/VA | 232 | 226 | 201 | 198 | 188 |
| VA/Empl. | 37.3 | 41.3 | 47.7 | 42.9 | 34.6 |
| **MACHINERY** | | | | | |
| kWh/VA | 197 | 183 | 146 | 130 | 137 |
| VA/Empl. | 34.2 | 38.3 | 47.8 | 49.4 | 39.6 |
| **PRECISION INSTRUMENTS** | | | | | |
| kWh/VA | 104 | 91 | 78 | 74 | 76 |
| VA/Empl. | 26.1 | 30.7 | 36.6 | 37.8 | 31.2 |
| **TRANSPORTATION EQUIPMENT** | | | | | |
| kWH/VA | 137 | 128 | 144 | 138 | 301 |
| VA/Empl. | 53.4 | 58.7 | 51:8 | 41.9 | 21.4 |

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EXHIBIT 10-1, page 2

ELECTRICITY AND EMPLOYMENT IN POLISH INDUSTRY (cont.)

| | 1987 | 1988 | 1989 | 1990 | 1991 |
|---|---|---|---|---|---|
| **ELECTRICAL & ELECTRICAL MACHINERY** | | | | | |
| kWH/VA | 154 | 138 | 131 | 124 | 119 |
| VA/Empl. | 34.6 | 40.5 | 41.9 | 42.7 | 39.8 |
| **CHEMICALS** | | | | | |
| kWh/VA | 446 | 425 | 495 | 571 | 590 |
| VA/Empl. | 106.5 | 115.9 | 103.0 | 82.0 | 62.6 |
| **CONSTRUCTION MATERIALS** | | | | | |
| kWh/VA | 624 | 610 | 549 | 486 | 541 |
| VA/Empl. | 38.9 | 41.0 | 49.7 | 45.9 | 38.8 |
| **GLASS** | | | | | |
| kWh/VA | 215 | 200 | 245 | 329 | 350 |
| VA/Empl | 52.4 | 57.1 | 50.3 | 37.5 | 34.9 |
| **CERAMICS** | | | | | |
| kWh/VA | 144 | 149 | 156 | 189 | 228 |
| VA/Empl. | 43.7 | 49.2 | 49.4 | 38.5 | 31.5 |
| **WOOD** | | | | | |
| kWh/VA | 265 | 248 | 207 | 296 | 251 |
| VA/Empl. | 31.7 | 35.6 | 46.5 | 33.4 | 25.4 |
| **PAPER** | | | | | |
| kWh/VA | 438 | 429 | 417 | 695 | 720 |
| VA/Empl. | 115.1 | 124.0 | 128.9 | 73.5 | 71.0 |
| **TEXTILES** | | | | | |
| kWh/VA | 176 | 162 | 154 | 222 | 203 |
| VA/Empl. | 44.3 | 50.7 | 52.7 | 31.4 | 30.3 |
| **CLOTHING** | | | | | |
| kWh/VA | 53 | 47 | 32 | 39 | 47 |
| VA/Empl. | 16.2 | 18.7 | 24.4 | 21.4 | 17.0 |
| **LEATHER GOODS** | | | | | |
| kWh/VA | 54 | 50 | 55 | 68 | 61 |
| VA/Empl. | 31.4 | 34.8 | 30.1 | 24.3 | 23.5 |

ELECTRICITY AND EMPLOYMENT IN POLISH INDUSTRY (cont.)

| | 1987 | 1988 | 1989 | 1990 | 1991 |
|---|---|---|---|---|---|
| **FOOD** | | | | | |
| kWh/VA | 54 | 57 | 72 | 85 | 79 |
| VA/Empl. | 165.8 | 160.0 | 127.2 | 101.0 | 90.5 |
| **PRINTING** | | | | | |
| kWh/VA | 96 | 91 | 71 | 77 | 116 |
| VA/Empl. | 23.6 | 26.7 | 31.3 | 30.9 | 20.1 |
| **OTHER** | | | | | |
| kWh/VA | 207 | 197 | 143 | 207 | 210 |
| VA/Empl. | 34.7 | 37.6 | 39.6 | 32.2 | 18.5 |

SOURCE: Ministry of Industry and Trade, Energy Information Center, CHARAKTERYS TYKI ENERGO-EKONOMICZNE GALEZI I BRANZ PRZEMYSLM (1992)

under "normal" conditions is probably somewhat less than recent data may indicate. Third, in many areas of Polish industry, production is not particularly electricity intensive, although heavy industry appears to be so.

The data in Exhibit 10-2 can be used to indicate the importance of electricity in total industry costs. Column 1 shows the number of kWh per million zlotys of output sold in 1991 for main industries. Because data on the actual electricity rates paid by each industry are not available, the average price paid by the industrial sector in 1991 (342 Zl/kWh) was used. If all industries paid the average price, then electricity cost as a percentage of sales is the figure shown in column 2. If all industries had exactly zero profit in 1991, then costs and sales would be equal and column 2 would approximate the percentage of electricity cost to total cost. For industries that were not profitable (a common event in 1991), the figures in column 2 overstate the importance of electricity in total cost, and vice versa. Also, if it is correct to assume that electricity intensity increases in the process of keeping employment artificially high, then the figures in column 2 would again over-state electricity costs as a percentage of the total.[3]

The data in Exhibit 10-2 indicate that electricity accounts for about 3.4 percent of industrial costs on average. There are some industries, notably heavy industries, where the proportion is higher. The non-ferrous metal industry includes aluminum which is highly electricity intensive.[4] Some chemicals are particularly electricity (and energy) intensive, and among construction materials, the main cement production techniques used in Poland are very electricity intensive. Nevertheless, electricity costs as a percentage of total costs are not high for the most part. The range is generally from about 1 percent to 5 percent of the total, but some industries exceed this.

Partial corroboration of these figures comes from a survey of selected industries based on 1990 conditions (column 3). These figures are generally higher than the first set, but they include cogeneration. The food industry is of particular concern when assessing the welfare of households (see below). Separate information on the food processing industry for 1992

[3] An additional factor may cause these figures to overstate electricity as a percentage of total cost. The original source obtains its data from firms that are relatively large (over 50 employees). If smaller firms are less electricity-intensive in their production technology and if these smaller firms were included in the data, the figures in column 2 would be lower.

[4] The only aluminum firm has a relatively constant demand of 120 MW. Electricity costs account for about 26 percent of total costs according to a representative of the firm.

# EXHIBIT 10-2

## ELECTRICITY COST IN TOTAL COST

| | kWh/Product Sold in million ZI. 1991 | Electricity Cost as % of Product sold 1991 | Electricity as % of Total Cost (A) |
|---|---|---|---|
| INDUSTRY OVERALL | 100 | 3.4 | |
| Coal | 189 | 6.5 | |
| Fuel | 42 | 1.4 | |
| Electric Energy | 269 | 9.2 | |
| Iron & Steel | 162 | 5.5 | 4.9 |
| Non-Ferrous Metals | 226 | 7.7 | 7.3 |
| Metal | 58 | 2.0 | 4.4 |
| Machinery | 49 | 1.7 | 4.6 |
| Precision Instruments | 29 | 1.0 | 3.6 |
| Transportation Equipment | 48 | 1.6 | 4.4 |
| Electrical Machinery | 7 | 1.3 | 3.3 |
| Chemicals | 151 | 5.2 | 6.7 |
| Construction Materials | 158 | 5.4 | |
| Glass | 97 | 2.8 | |
| Ceramics | 78 | 2.7 | |
| Wood | 53 | 1.8 | 4.3 |
| Paper | 237 | 8.1 | |
| Textiles | 65 | 2.2 | |
| Clothing | 15 | 0.5 | |
| Leather Goods | 17 | 0.6 | |
| Food | 23 | 0.8 | 2.1 |
| Feed | 28 | 1.0 | |
| Printing | 21 | 0.7 | |
| Other | 67 | 2.2 | 3.6 |

Source: Some as Table 12.1 except A. Which is the results of a questionaire administered by GUS for the Ministry of Industry and Trade, 1990

reveals that the overall energy costs (which include electricity) for the first 6 months of 1992 averaged only 2.6 percent.

### Summary

Electricity costs are probably not the largest problem facing Polish industry at this time. The problems associated with privatization, changing product prices, changing technology, shifts in product choice, depressed aggregate demand, and the installation of normal market incentives tend to make the problem of rising real electricity prices seem rather slight.

World Bank (1992) studies illustrate the institutional problems remaining and the incentives still lacking before industrial firms can operate on a market basis. State-owned industries (the majority) have been slow to adjust and their output still appears to be in decline. Mining, some chemicals, cement and aluminum production are intensive in the use of electricity. For them, electricity pricing is a major concern, but in these cases, opportunities for energy conservation can be easily identified (Pasierb, 1992). Of greater concern to most firms is whether they will continue to exist under any circumstances in a free market environment. Industrial net profits were negative for the first eight months of 1992 (World Bank, *Economic Update*, October 1992), despite a slight increase in real output. The fact that the real price of electricity to industry declined between 1991 and 1992 seems consistent with the notion that factors other than electricity prices predominate.

### Conclusions

Electricity prices are not a factor that will make or break Polish industry. More important factors are easily identified. However, industrial customers should be given greater flexibility in striking contracts with the entities that offer them the most favorable price and delivery conditions. Currently, industrial enterprises do not have many options in terms of service and rates.

## 10.2 THE IMPACTS ON AGRICULTURE AND TRANSPORTATION

Agriculture and transportation are of particular interest to the assessment of household budgets. Food occupies a relatively large part of most household budgets in Poland. The transportation system is usually a key factor in people's ability to work, and in Poland a large part of the transportation system is by electric tram or train. Therefore, interviews

were held with several specialists in various aspects of agricultural and food production. Also, several representatives of the railroad (PKP) were interviewed.

### Agriculture

Although specific data were not available on electricity as an input to farm production, there is a consensus that production is not very electricity-intensive. Furthermore, PPGC and distribution company data confirm that little electricity is used for production on most Polish farms. Most farms have only one meter, serving both the home and farm operations. Average annual use (in the F1 rate class) is only 2,000 kWh. Distribution company representatives and agricultural specialists estimate that only 20 percent of that goes toward farm production; the remainder is used in the home. Therefore, it is not likely that non-farm households' budgets will be affected much by electricity price increases to farmers.

It is interesting to note that everyone interviewed indicated an unmet demand for increased electrical service on farms. Most farms are served by a very weak distribution system that was installed shortly after World War II.[5] Many farms would like to install increased numbers of electrically-driven devices, but overly loaded distribution systems do not permit it. Distribution companies receive many requests for increased service, but are unable to respond under current conditions.

### Transportation

The transportation system in Poland relies heavily on electric trains and trams. Of the 23,000 km of track in Poland, 11,000 are electrified. Most freight and almost all passengers are moved by electric power.

Currently, there is no clear transportation policy. The rail company (the PKP) is heavily subsidized. Rates for service are set without regard to cost, and rates for passenger service appear to be far below actual costs. Budget constraints have cut the subsidy flowing to the PKP in recent years, but allowed rate increases have fallen well short of inflation. As a result, the PKP system is probably deteriorating physically and service is being reduced.

[5] The system installed then was a first effort at rural electrification. Some rural distribution systems were upgraded in the 1970s, but those improvements were aimed mainly at serving state farms. Most state farms are now bankrupt. About 80 percent of all farms are private and are still served by the distribution system installed almost fifty years ago.

Meanwhile, PKP has fallen into arrears in its payments to electric distribution companies and to other suppliers. The distribution company surrounding Warsaw alone is owed over 20 billion Zl by PKP, and PKP has no obvious solution available to it for making payment.

It is difficult to estimate how transportation rates would behave should the price of electricity paid by PKP rise. PKP estimates that only 5.6 percent of its total costs are associated with electricity purchases. However, because transportation rates are not cost-based, how they would be affected by electric tariff increases is not clear.

### Conclusions

Electric pricing for Polish agriculture appears to be a minor problem. No special treatment seems justified for agricultural customers, except insofar as they reflect differences in the cost of service.

There is an apparent unmet demand for power in the agricultural sector. Special attention should be directed toward developing a distribution system upgrade and expansion plan in rural areas.

The transportation system appears to be in some disarray due to a lack of clear policy. The PKP is one of the electric system's largest customers, yet it has been put in a position where it cannot recover its own costs and cannot rely on subsidies to make up for losses. PKP arrears with the distribution companies that serve it are almost assured until PKP is put on a self-sustaining basis.

## 10.3 THE IMPACTS ON HOUSEHOLDS

Household budget information is available from the Government Statistical Office (GUS).[6] Because data are available for all of 1991 and for the first three quarters of 1992,[7] the

[6] Three sources were used here. GUS (1992a) is a statistical yearbook for general data through 1991. GUS (1992b) provides detailed household information, including data on income and expenditures, through 1991. GUS (1993) provides abbreviated data, similar in coverage to GUS (1992b), but reported quarterly, through the third quarter of 1992. Data from GUS documents are consistent across documents.

[7] To abbreviate, the notation "year:quarter" will be used (e.g., the first quarter of 1992 is 1992:1).

analysis focuses first on 1991, and then qualified estimates are made of budgets as of the end of 1992 and early 1993. The estimates for early 1993 are only general approximations.

GUS regularly collects data from a large, stratified sample of Polish households.[8] The stratification separates households into four categories:

- **Employees.** Where the head of household works in business and trades, including work in state organizations. About 42 percent of all households surveyed fall in this category. This group is divided into two classes: wage earners and salaried workers.

- **Employees/farmers.** Where the household head is an "employee" (as above) but also where part of the family income comes from farming. Eleven percent of households are in this group.

- **Farmers.** Where the household's primary income is from farming. Eleven percent of households are farmers.

- **Retirees and pensioners.** Households in this group receive the largest part of their income from pensions, although they may also work in one of the other categories. Thirty-six percent of households fall in this group. Retired persons fall in the other categories if their income from work exceeds their income from retirement.

Exhibit 10-3 shows a summary of data on households and their 1991 incomes from the GUS documents. All data on incomes and expenditures are stated in thousand zlotys, or kilo-zlotys (kZ) unless otherwise specified. Households averaged 3.1 persons; households of retirees were smaller than average (1.9 people) and those on farms were larger. All income figures shown are net of taxes and include social benefits. While there was some variation in average household income across the groups, the variation is largely a function of the number of people in the household. Per-household monthly net income averaged 2,929 kZ,[9] but ranged from 1,816 kZ for retirees to 4,391 kZ for employee/farmers.

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[8] For a description of the survey and sampling technique, see GUS (1992b), pages xxiii - xxx.

[9] About $266, given average exchange rates for the period. Average per capita net income was about $1,130 per year.

# EXHIBIT 10-3

## HOUSEHOLD CHARACTERISTICS, 1991

| | AVERAGES: HH SIZE | HH INCOME Z/000) | INCOME PER PERSON | % OF HH (A) |
|---|---|---|---|---|
| ALL HOUSEHOLDS | 3.1 | 2929.4 | 945.1 | 100.0 |
| EMPLOYEE HH | 3.5 | 3468.7 | 979.0 | 41.8 |
| WAGE | 3.7 | 3200.0 | 857.9 | 25.8 |
| SALARY | 3.3 | 3836.4 | 1176.5 | 16.1 |
| EMPLOYEE/FARM | 4.7 | 4390.5 | 930.2 | 11.0 |
| FARM | 3.8 | 3108.1 | 823.9 | 10.9 |
| RETIRED/PENSIONERS | 1.9 | 1818.0 | 948.9 | 36.3 |

SOURCE. GUS (1992) p. 216, table 8(3211).
except A, which is p. 213, table 3(3161)

Very little variation in income exists in per capita terms. Per capita incomes on farms seem lowest, but are probably under-stated due to the consumption of food items produced at home, and the fact that few farm households pay rent. Incomes of retirees, which seem low on a per household basis, are about average in per capita terms. Some inequality exists within categories. Within employee households, GUS distinguishes between wage and salary earners. Average per capita incomes within salaried households (1,177 kZ per month) exceeded those of wage-earning households (858 kZ) by about 37 percent. However, this per capita inequality is offset by the fact that wage-employee households are larger. Thus, there is less inequality in terms of household income than first appears.

Exhibit 10-4 shows expenditures per household. These are sorted out by broad category of expenditure.[10] Electricity is separated from other energy, where the latter includes heat, natural gas, and other fuels. Transportation fuels are included in the "transportation" category. As percentages of household income, expenditures on energy overall are moderate, ranging from 5.3 percent of income for the employee and employee/farmer categories to 9.7 percent for retirees. While both farmers and retirees spend more on energy than other households, most of the difference is accounted for by non-electrical energy. Farmers are not likely to have access to district heating and must therefore heat with other fuels. While retirees' households often have access to district heating, these households are smaller. For them, the cost of heating a dwelling is spread over fewer people and a smaller income, causing the proportion of income spent on "other energy" to appear extraordinarily high. In money terms, retiree households spend about the same amount on "other energy" as other households and spend less on electricity.

These observations indicate that as a proportion of household expenditures, electricity expenditures are not very great. The proportion of income spent on electricity is generally about 2 percent, although it may range up to 2.8 percent for households of retired persons.

Similar conclusions are reached if utility data are used instead of expenditure survey data. PPGC data are available for all rate classes for calendar year 1992. These data show the total numbers of customers, energy sales to rate classes, and average revenue from each. The rate class that is most commonly occupied by "employee households" (G1) applies to

[10] This exhibit identifies "savings," which are defined as income minus the expenditures that have been specified. Some families have debts, and debt service must come out of "savings." In other cases, inter-household transfers or gifts are made, which would affect the savings category. These cases are labelled "savings" but are not savings as normally calculated. Rather, they represent an amount of income left over after normal expenditures that may be used for other purposes, some of which may include saving. It may also be possible that households have not recorded all expenditures (a common occurrence with surveys of this type).

# EXHIBIT 10-4

## HOUSEHOLD EXPENDITURE PATTERNS, 1991

PART A: PER CAPITA IN Z(000), MONTHLY

| | EMPLOYEE HH | EMPLOYEE/ FARM | FARM | RETIRED/ PENSIONED | AVERAGE WAGE-EARNER |
|---|---|---|---|---|---|
| FOOD | 369.8 | 344.3 | 381.7 | 445.0 | 348.5 |
| ALCO+TOBAC | 29.6 | 25.1 | 27.6 | 24.8 | 28.7 |
| CLOTHING | 91.6 | 75.2 | 67.0 | 74.5 | 77.9 |
| HOUSING | 69.4 | 77.5 | 60.1 | 96.0 | 74.5 |
| HEALTH | 36.8 | 21.8 | 22.8 | 43.3 | 29.3 |
| ENTERTAINM'T | 100.1 | 46.4 | 41.4 | 50.5 | 75.0 |
| TRANSPORT | 78.2 | 64.5 | 59.2 | 49.9 | 52.1 |
| ELECTRICITY | 19.2 | 16.6 | 20.8 | 26.5 | 17.4 |
| OTHER ENERGY | 32.3 | 32.4 | 35.0 | 65.8 | 30.5 |
| OTHER | 34.7 | 30.8 | 42.9 | 37.5 | 3.1 |
| TOTAL | 879.7 | 734.2 | 758.2 | 923.9 | 737.0 |

PART B: TOTAL AVERAGE EXPENDITURES PER HH MONTHLY

| | EMPLOYEE HH | EMPLOYEE/ FARM | FARM | RETIRED/ PENSIONED | AVERAGE WAGE-EARNER |
|---|---|---|---|---|---|
| FOOD | 1309.1 | 1625.1 | 1439.0 | 845.5 | 1288.9 |
| ALCO+TOBAC | 104.8 | 118.5 | 104.1 | 47.1 | 107.1 |
| CLOTHING | 325.0 | 354.9 | 252.6 | 141.8 | 290.6 |
| HOUSING | 318.5 | 366.6 | 226.6 | 182.4 | 277.9 |
| HEALTH | 129.8 | 102.0 | 85.2 | 82.3 | 109.3 |
| ENTERTAINM'T | 354.4 | 219.0 | 156.1 | 115.0 | 279.8 |
| TRANSPORT | 268.7 | 304.4 | 223.2 | 94.8 | 194.3 |
| ELECTRICITY | 68.0 | 78.4 | 78.4 | 50.4 | 64.9 |
| OTHER ENERGY | 114.3 | 152.9 | 132.0 | 125.0 | 113.7 |
| OTHER | 123.8 | 144.4 | 161.7 | 71.3 | 11.6 |
| TOTAL | 3114.1 | 3466.4 | 2858.6 | 1755.2 | 2746.0 |
| INCOME | 3466.7 | 4390.5 | 3106.1 | 1816.0 | 3200.0 |
| SAVINGS | 351.6 | 925.1 | 247.3 | 60.8 | 451.0 |
| AS % OF INCOME | | | | | |
| ELECTRICITY | 2.0 | 1.8 | 2.5 | 2.8 | 2.0 |
| OTHER ENERGY | 3.3 | 3.5 | 4.2 | 6.9 | 3.6 |

SOURCE. Previous table: GUS(1992a), pp216–219, table 9(322)

GUS(1992b) p.25 table 8, p.112 table 7(24),
p.176 table 6(35), p.242 table 7(47).
Electricity separated by Energy Information Center

about 9.7 million customers. Within that rate class, 1992 average energy consumption was 1,675 kWh per customer. Average revenue per kWh in that class was Zl 619. Thus, the average annual expenditure per customer was about 1 million zlotys, and the average monthly expenditure was about 87 kZ per month. GUS (1993) data indicate that household income for "employees" was about 4,400 kZ per month for the same period.[11] Thus, average expenditures on electricity account for about 2 percent of the total average incomes of households of "employees." If the same calculations were performed for 1991, electricity would have amounted to about 1.4 percent of employees' household incomes.

Similar calculations for the rate class most often applicable to farms (F1) indicate that farm customers spent about 100 kZ per month. GUS data indicate that farm household incomes were around Zl 4 million per month. Electricity would have occupied about 2.5 percent of farm household income.[12] In 1991, by the same calculation, electricity took about 2 percent of farm household income. On farms, one should separate electricity used for normal household functions from that used for agricultural production. Most farms have only one meter, so an exact separation is not possible. However, people knowledgeable about farm production conditions in Poland estimate that only about 20 percent of electricity used on farms is used to support production. The remainder is for household use. If this is the case, then Polish farm households are much like urban households in that about 2 percent of the household budget goes to purchase electricity for household uses.

In both cases, where household types can be associated with a rate class (as in the case of employees with G1 and farmers with F1), average electric energy consumption for the rate class declined between 1991 and 1992. In the residential rate class (G1), average energy consumption declined by about 3.6 percent, while among farm customers (in rate class F1), average energy consumption dropped by 7 percent. In both rate classes, average revenue per kWh increased by almost 30 percent in real terms, although real monthly household income remained unchanged during the period. While these declines in energy consumption may be a continued response to the economically depressed conditions in Poland, they are consistent with normal expectations about short-run price elasticities.

[11] The GUS data do not cover 1992:4. The income referred to here is for the period 1991:4 through 1992:3. Thus, the utility data and the GUS data almost match up, but not quite.

[12] It is not very clear where "employee/farmer" or "retired/pensioner" households fall within electric rate classes.

The far right-hand column of Exhibit 10-4 displays data for an average household, where the household head is a wage earner. This is meant to represent a lower-middle income family.

Expenditures on electricity for this kind of family are slightly less than they are for other households, but the proportion of household income spent on electricity is about the same: 2 percent.

Exhibit 10-5 depicts more recent household budgets. Because there is very little variation in budgets across household types, only "employee" and "pensioner" households are reported; together these two groups represent about 78 percent of all households. Exhibit 10-5 represents an "average" monthly budget, given conditions as of the end of 1992:3, where the average accounts for seasonal variation. GUS (1993) reports household incomes and expenditures quarterly for 1991 and 1992, but only through 1992:3. The GUS data are expressed in current zlotys of the quarter in which they occur. Unfortunately, quarter-to-quarter inflation is high enough that simply adding the last four quarters together gives an under-estimate of expenditures in zlotys at the end of period. Simple quarter-to-quarter addition adds inflated zlotys to some with less inflation. Fortunately, the GUS data provide category-specific price changes for each of the expenditure types. To place these figures in zlotys as of the end of 1992:3, each quarter's expenditure, and each category within, has been adjusted upward to represent the inflation that occurred between the time it was recorded and 1992:3.[13]

As of 1992:3, "employee" household energy expenditures had reached an average of about 7.2 percent of income, up from about 5.3 percent in 1991 and from as low as about 3 percent in the late 1980s. Energy expenditures required an even greater share of pensioner income, about 11.8 percent in 1992:3 up from 9.8 percent in 1991. Further, it is worth noting that average total expenditures of pensioners actually exceeded their household income in late 1992.

Because these data do not separate expenditures on electricity from those on other energy resources, the price increases that have occurred in each kind of energy were used to infer the proportion of electricity in the energy budget (Exhibit 10-6). All energy forms shown are sold at regulated prices, except for "coal and other fuels"; thus, price increases are known. For coal and other fuels we assumed that prices increased about in line with

[13] For example, food expenditures for the 1991:4 quarter are adjusted upward by the amount of inflation occurring in food items during each of the subsequent quarters, 1992:1-3.

Exhibit 10-5

**Monthly Average Household Budgets, 1992:3**
**('000 Zl of 1992:3)**

## A. Employees' Households

| | Per Capita | Household | % of Income |
|---|---|---|---|
| Total Expenditure | 1221.8 | 4325.2 | 86.4 |
| | | | |
| Food | 513.5 | 1817.8 | 36.3 |
| Alcohol,Tobacco | 37.0 | 131.0 | 2.6 |
| Clothing | 88.0 | 311.5 | 6.2 |
| Housing | 139.5 | 493.8 | 9.9 |
| Health | 57.2 | 202.5 | 4.0 |
| Entertainmt/Educ. | 125.5 | 444.3 | 8.9 |
| Transp.Commun. | 94.6 | 334.9 | 6.7 |
| Energy | 102.4 | 362.5 | 7.2 |
| Other | 64.1 | 226.9 | 4.5 |
| | | | |
| Savings | 191.8 | 679.0 | 13.6 |
| | | | |
| Total Income | 1413.6 | 5004.2 | 100.0 |

## B. Retired Persons and Pensioners Households

| | Per Capita | Household | % of Income |
|---|---|---|---|
| Total Expenditure | 1313.9 | 2525.3 | 100.9 |
| | | | |
| Food | 646.8 | 1243.1 | 49.7 |
| Alcohol,Tobacco | 35.0 | 67.3 | 2.7 |
| Clothing | 64.6 | 124.2 | 5.0 |
| Housing | 148.3 | 285.0 | 11.4 |
| Health | 77.6 | 149.1 | 6.0 |
| Entertainmt/Educ. | 70.2 | 134.9 | 5.4 |
| Transp.Commun. | 65.6 | 126.1 | 5.0 |
| Energy | 154.1 | 296.2 | 11.8 |
| Other | 51.7 | 99.4 | 4.0 |
| | | | |
| Savings | −11.8 | −22.7 | −0.9 |
| | | | |
| Total Income | 1302.1 | 2502.6 | 100.0 |

Source: GUS (1993).

inflation, i.e., by 40 percent. During 1992, the cost of heat and hot water to households was increased in nominal terms by about 169 percent. Heat prices increased by 158 percent and hot water by 180 percent, while electricity and gas prices rose by 42.5 percent and 89.6 percent, respectively.

Meanwhile, household incomes were increasing in nominal terms about in line with inflation (44 percent). Thus, as the price of electricity was rising, its proportion of energy expenditures was falling[14] slightly since electricity price increases kept pace with the general inflation rate, while other energy forms had price increases exceeding inflation. By the third quarter of 1992, electricity probably represented about 30 percent of the "employee" household energy budget expenditures and about 2.2 percent of household income. For the pensioner household, electricity may have represented only about 22 percent of energy expenditures, but about 2.6 percent of the total household budget.

After 1992:3, GUS data are not available, but the scheduled 1993 price increases for electricity, gas, and heat & hot water are known. (In the absence of more detailed data, we again assume that coal and other fuel prices keep pace with inflation.) These data, also reported in Exhibit 10-6, permit us to approximate the contribution of electricity and other types of energy to the household budget as of the end of 1993. While other fuels (notably heat & hot water) will experience even greater price increases, retail electricity prices will increase more rapidly than inflation through 1993. Electricity is expected to consume a rising share of the total budget, in the range of 2.6 to 3.1 percent. Further, the statistics suggest that total energy expenditures will increase by about 25 percent in real terms, representing about 9 percent of the "employee" household budget and almost 15 percent of the pensioner budget.

Two reasonable interpretations of this data are possible. They can be summarized briefly as follows:

(1) Because households spend only 2.5 to 3 percent of their total income on electricity, a large real price increase would have only a small effect on household well being. For example, a 75 percent increase in the real price of electricity, in the first quarter of 1994, would cause households to spend an additional 2 to 2.25 percent of income on electricity (assuming no conservation). In isolation, this increase would not appear to be disruptive.

[14] This discussion assumes that the households in question have district heating and hot water. Both "employee" and "pensioner" households are likely to be in cities and therefore likely to be district heating customers.

Exhibit 10-6

**Energy Price Increases, 1991 – 93**
**(all values in percent)**

**A. Employees' Households**

| Fuel | Share of Household Expenditure 1991 1/ | | Price Increaase 1991 – 92:3 2/ | Inferred Share of Household Expenditure 1992:3 | | Price Increaase 92:3 – 93:4 3/ | Inferred Share of Household Expenditure 1993:4 | |
|---|---|---|---|---|---|---|---|---|
| | Energy Budget | Total Budget | | Energy Budget | Total Budget | | Energy Budget | Total Budget |
| Electricity | 38 | 2.0 | 43 | 30 | 2.2 | 67 | 29 | 2.6 |
| Gas | 21 | 1.1 | 90 | 22 | 1.6 | 51 | 19 | 1.7 |
| Heat, Hot Water | 23 | 1.2 | 169 | 34 | 2.5 | 101 | 40 | 3.5 |
| Coal & Other | 19 | 1.0 | 40 | 15 | 1.1 | 54 | 13 | 1.2 |
| Total | 100 | 5.3 | 81 | 100 | 7.2 | 74 | 100 | 9.0 |

**B. Retired Persons and Pensioners Households**

| Fuel | Share of Household Expenditure 1991 1/ | | Price Increaase 1991 92.3 2/ | Inferred Share of Household Expenditure 1992:3 | | Price Increaase 92:3 - 93:4 3/ | Inferred Share of Household Expenditure 1993:4 | |
|---|---|---|---|---|---|---|---|---|
| | Energy Budget | Total Budget | | Energy Budget | Total Budget | | Energy Budget | Total Budget |
| Electricity | 29 | 2 8 | 43 | 22 | 2.6 | 67 | 21 | 3.1 |
| Gas | 24 | 2 3 | 90 | 24 | 2.9 | 51 | 21 | 3.1 |
| Heat, Hot Water | 26 | 2 5 | 169 | 38 | 4.4 | 101 | 43 | 6.4 |
| Coal & Other | 21 | 2 1 | 40 | 16 | 1.9 | 54 | 14 | 2.1 |
| Total | 100 | 9 8 | 86 | 100 | 11.8 | 74 | 100 | 14.7 |

1/ Based on 1991 annual average energy budget.
2/ Source: GUS (1993).
3/ From Department Polityki Finansoweji i Analiz for 1993 forecast; 1992:4 assumed price increases – electricity (4.9%), gas (5%), heat & hot water (5%), other (10%)

(2) A 2 to 2.25 percent increase in electricity's demand on household expenditures might be "the straw that broke the camel's back". Prices of most other energy sources have been increasing more rapidly than inflation, and the share of energy in the total household budget has more than doubled since 1990. As noted above, energy will represent nearly 15 percent of a pensioner household budget by 1994. Of course, households must also adjust to some dramatic price increases outside the energy sector.

Households would also be affected indirectly if electricity price increases were passed on to producers of the other things that households consume. Most important in the household budget is food. Fortunately, food production in Poland is not particularly electricity intensive (see the discussion above on industry). About 2.2 percent of the costs of food are attributable to electricity inputs. If real electricity prices to food producers increased by 75 percent as well, given that food occupies about 35 percent of the household budget, expenditures on food would increase by about 0.6 percent.

Transportation may also be important since most people commute to work on electric trains. Evidence suggests that only a very small part of a typical household budget is spent on electrically driven, public transportation. According to GUS data only about 1 percent of the budget is spent on passenger transport and about another 1 percent on freight. Since only 5.6 percent of the rail system's costs are for electricity, the impact of electricity price increases on households, acting through the rail system, would be negligible.

### Summary

As of late 1992, a 75 percent real increase in electricity prices could increase household expenditures by about 2.5 to 3 percent of incomes. Of this, 2 to 2.25 percent would be through the direct use of electricity and 0.6 percent through higher food prices. Other consumption items would have very small effects. These estimates must be considered very approximate, for the data upon which they are based are very weak. Furthermore, much depends upon what happens to household incomes as electricity prices rise, and on how households reallocate their expenditures.

The impact of a large electricity tariff increase on household budgets may at first appear negligible. Taken in the context of a rapidly rising prices in all sources of energy and in other sectors of the economy, the adjustments appear more burdensome. Further, even a 3

percent increase in expenses in the household budget is dramatic if resources are strained.[15,16]

### Consumer Responses

In most cases where prices increase, reduced consumption can be expected. Although there are no recent studies of the price elasticity for electricity in Poland, there are two main reasons to think that the reduction in consumption among residential customers is likely to be slight. First, electrical energy consumption, on average, is already very low (1,675 kWh per year). Furthermore, about one-third of residential customers consume less than 1,000 kWh per year. Among many of these customers, it is not likely that significant reductions will occur for many uses of electricity other than basic lighting.

A second reason relates to the way residential customers are billed. All residential customers receive a payment book, with payments to be sent in bi-monthly. Books are issued once per year and are based upon forecast consumption. At the end of each year, adjustments are made for consumption that was different than the forecast and for rate changes that occurred during the year.[17] For most customers, this implies modest payments during the year and a very large payment at the end. Even in cases where kWh consumption has declined, the settlement at year-end can give the impression that conservation doesn't pay.

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[15] In 1992:3, GUS data indicate that the household budget of retired persons and pensioners (representing 36 percent of all households) exceeded monthly income by almost 1 percent.

[16] In light of the political nature of electric tariff increases and the difficult economic position of many low-income families in Poland, one option to consider is a residential tariff with two or three rate blocks. Given the pattern of residential electric consumption in Poland, such a step may give relief to lower-income families without affecting average families very much. The amount of electric energy consumed by the lowest consumption group is so small that the revenue loss associated with a lower-priced first block is not very large, and total electric bills for average consumers may not be affected much when revenue is recuperated in higher blocks. This option is discussed in more detail in Chapter 10.

[17] This creates a financial problem for the entire utility system. Currently, generators bill PPGC every five days, but settle accounts monthly. PPGC does the same for distribution companies. However, distribution companies experience a lag in receiving revenue, since they collect from end-users based on forecasts, with a large adjustment in the bill at the end of the year. Payment booklets are issued year round, so some catch-up payments are received at all times. However, when tariffs are increasing rapidly, the resulting revenue increases trickle into the distribution companies over the course of a year. Yet the distribution companies must settle accounts with PPGC monthly.



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Furthermore, customers may not know how much they are consuming month to month because their bi-monthly payment gives them no guidance. Finally, even the utility may not be able to tell them what their consumption is because of meter reading problems. Normally, meters are read only once per year, in order to settle the account from the preceding year and prepare a forecast for the next. Meters are normally inside each customer's home, especially in older homes (i.e., over ten years old), so someone must be at home to have the meter read. Thus, meter reading may require repeated visits until someone is found at home.[18] Under these circumstances it is not likely that people even know how much they are spending on electricity service.[19] Without this information, it is not likely that rational decisions can be made about electricity consumption.

### Conclusions

Electricity expenditures represent a small portion of the average household budget in percentage terms. Expenditures related to all energy requirements, however, represent a more significant share of income. Statistical data suggest that if electricity were the only good needing a significant real price increase, this increase could be passed to final consumers without damaging household welfare. Unfortunately, electricity is only one of many goods in need of real price adjustments. Therefore it is reasonable that policy-makers call for gradual real price adjustments as the electric sector moves steadily toward tariffs which provide for full financial cost-recovery.

Based on discussions with PPGC management, which in turn reflect PPGC discussions with the Government, we believe that real tariff increases on the order of 10 to 15 percent per year represent the maximum acceptable average annual upward adjustment of prices in today's economic environment. Thus, although the pure financial evaluation presented in Chapters 8 and 9 identifies the need for greater tariff increases, it is recommended that financial leverage be employed to "phase in" tariff adjustments gradually over several years.

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[18] It is not uncommon for meters to be unread for as long as two years.

[19] Recently, a Polish research foundation attempted to solicit information about energy consumption from individuals in focus group settings. People were asked about how much they were spending on electricity. Responses were over twice what one would have expected from other information. This exercise revealed that people could only guess what they spent on electricity.

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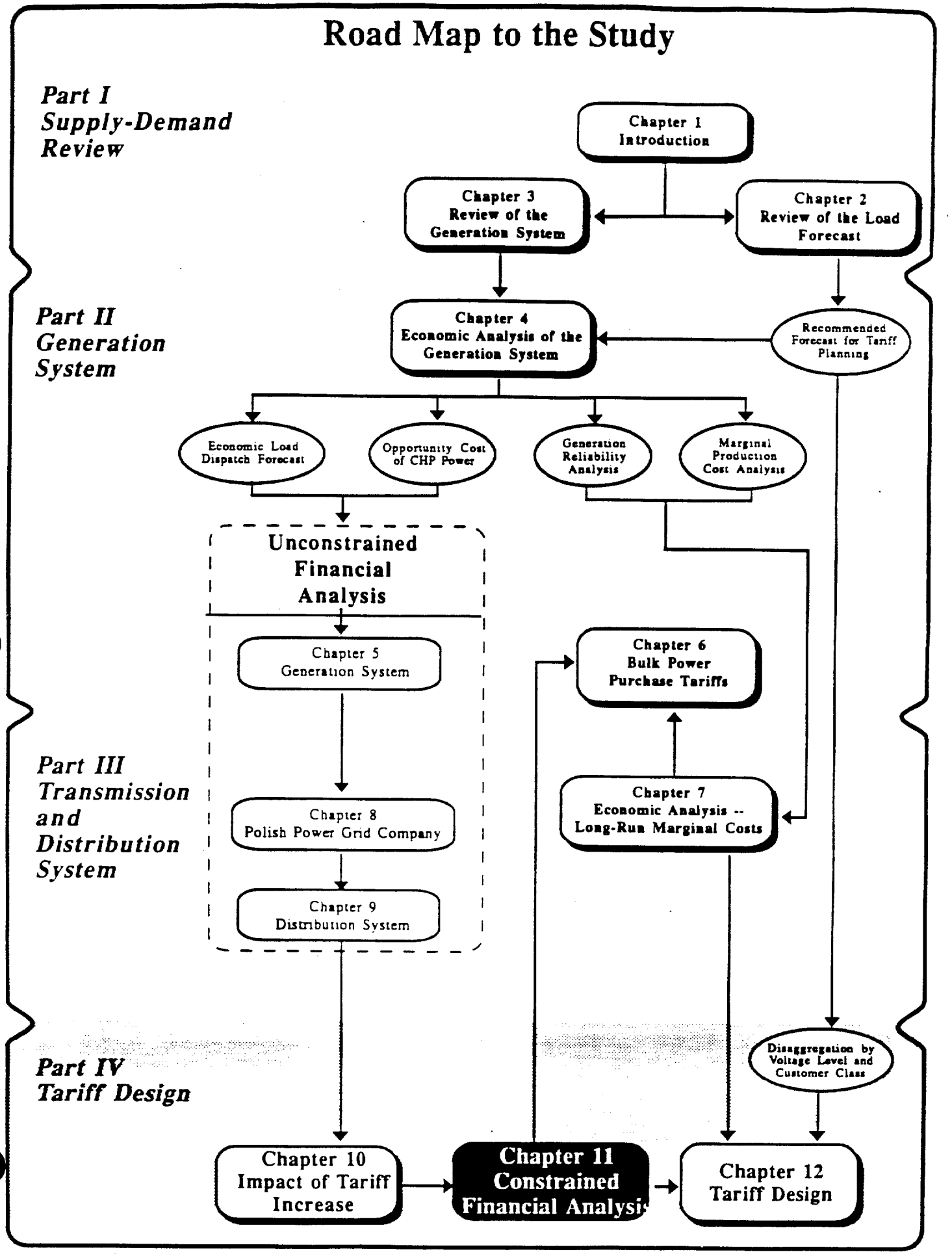
# Road Map to the Study

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In Chapter 9 it was concluded that if revenues at retail level for 1994 could be, in real terms, 45 percent higher than in 1992, then a full adjustment of the pricing system for the power sector would be possible providing the resources needed to maintain and expand the system while providing acceptable rates of return on a realistic value of the assets. However, in Chapter 10 it was concluded that, it may not be possible for real retail tariffs to increase at more than 15 percent per year.

In addition to these constraints on tariff increases the decisions regarding asset revaluation do not rest entirely within the power sector and there is a real possibility that asset revaluation may need to proceed gradually if at all, in order to avoid sudden increases on depreciation allowances for tax purposes. Also, it is likely that by the end of 1993 there would be hardly any real growth in electricity prices with respect to mid-1992.

The objective of this Chapter 11 is to examine the effect of these constraints on the financial outlook of the power sector to arrive at a realistic level of revenues for the period 1994-1997. At the same time, the major uncertainties affecting the analysis are examined to develop a perception of the range of results that can be expected.

## 11.1 CONSTRAINED CASES

It is appropriate to refer to the financial analysis completed in Chapter 9 as the unconstrained analysis in the sense that is not affected by limitations external to the power sector. The cases to be studied in this chapter are all constrained by combinations of the following:

- a ceiling on the real annual growth of average tariffs at retail level
- a ceiling on the annual rate of revaluation of assets
- a ceiling on the depreciation allowance for tax purposes

Three cases are being considered:

### Case 1 - Tariff Increase Restriction Only

Based on the conclusions of Chapter 10 it appears that a 15 percent real increase in average retail tariffs is the maximum that can be applied from one year to the next without serious negative public reaction. Since little progress is expected in real revenue increases from calendar years 1992 to 1993 it will be assumed that average 1994 revenues at retail level can be only 15 percent higher, in real terms, than 1992 increasing at a maximum of 15 percent per year thereafter until other financial performance criteria become binding.

### Case 2 - Tariff Increase Restriction and No Asset Revaluation

Keeping the ceiling on tariff increases as described for Case 1, this case simply assumes that no revaluation of assets is possible.

### Case 3 - Tariff Increase Restriction and Gradual Asset Revaluation

Based on discussion with PSE it appears that a gradual revaluation is possible and it has been assumed that, by 1997, gross assets could be valued at 100 percent of their replacement cost while depreciation allowance may be limited to only 70 percent of revalued gross assets.

Case 3 is considered to be the most likely scenario and therefore sensitivity analysis with respect to major uncertainties are made keeping the same constraints. Two cases were considered:

### Case 3a - High Capital Investments in the Generation System

The analysis described so far estimates that the system will need approximately six billion US dollars in capital investments during 1994-1997. There is a great deal of uncertainty about this figure and currently studies are being conducted to better forecast these needs. To examine the impact of higher investment Case 3a considers a 50 percent increase in the level of required investment to approximately nine billion dollars during 1994-1997.

### Case 3b - High Operating Costs in the Generation System

It has been assumed that operating costs would decrease from current levels as the system becomes modernized and operating efficiency is rewarded. While this is certainly likely at a very high level of investments it is less likely at more modest levels since some capital investments may continue to be shown as operating expense. To examine this possibility Case 3b considers no drop in operating expense from current levels.

## 11.2 APPROACH TO THE ANALYSIS OF FINANCIAL CONSTRAINTS

In order to analyze these different cases it was necessary to simplify the process followed through the detailed financial analyses of the generation, transmission and distribution systems described in Chapters 5, 8 and 9 respectively. Essentially, the analysis of financial constraints is performed on the basis of aggregated generation instead of the plant by plant analyses carried

out in Chapter 5. Therefore, the financial forecasts for 1994-1997 presented in this section are less accurate than those presented for the unconstrained case.

However, in order to allow for clear comparison against the unconstrained case, completed in Chapter 9 the results for this case are first presented, in Exhibit 11.1 in the same form as that will be used for the constrained cases.

## 11.3 RESULTS OF THE ANALYSIS OF FINANCIAL CONSTRAINTS

### Case 1 - Tariff Increase Restriction Only

The results of this analysis are shown in Exhibit 11.2 where it can be observed that average retail tariffs in 1994 are 15 percent higher than 1992 levels and increase an additional 15 percent by 1995. After 1995 only a 10.9 percent increase is required to bring the system to the recommended level.

Since it is reasonable to maintain a no net borrowing criterion for the distribution companies the burden of a lower tariff yield in the short term is assigned to the generation system reducing its average tariff yield from 488.9 Zl/kWh to 351.0 Zl/kWh. This results in a significant loss for the generating system (given border prices for coal) at the operating income and net income levels, leading to a significant increase in the cash deficiency or net borrowing requirement for the generating system. Even so, with a borrowing requirement of about zl 15,000 billion in 1994, the projected debt-to-equity for the generating system is about 5.0%.

### Case 2 - Tariff Increase Restriction and No Asset Revaluation

In this case shown in Exhibit 11-3, not only is the retail tariff constrained, but the elimination of revaluation reduces the depreciation expense which can be claimed as a deduction for tax purposes, thereby reducing annual cash flow to the distribution system. To offset this effect, it is necessary to reduce the bulk purchase price paid to PSE.

Thus the PSE selling prices are reduced in 1994 and 1995, in turn forcing a reduction in the price paid to the generating system.

By 1996 generating companies are able to approach a 6.0% rate of return, however, because the assets are not revalued this return is insufficient to cover the financing costs on the ever-increasing cash deficiency.

# Exhibit 11-1
# NON-CONSTRAINED CASE

Assumptions:

Retail tariff increase: No constraint

Asset Revaluation: 100% of replacement cost by January 1994

Tax allowance from Depreciation: 100% of replacement cost by January 1994

Investments in generation 1993 - 1997: US$ 5.8 billion

Fixed Operation Costs: decreasing

Financial criteria for DCs: no borrowing

| | ESTIMATE | FORECAST | | | |
|---|---|---|---|---|---|
| | 1992 | 1994 | 1995 | 1996 | 1997 |
| **AVERAGE TARIFFS - Zl/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 542.1 | 785.0 | 785.0 | 795.0 | 805.0 |
| PSE | 336.7 | 563.0 | 557.0 | 559.0 | 571.0 |
| Generation System | 300.0 | 488.9 | 487.2 | 490.6 | 504.2 |
| **AVERAGE TARIFFS - US cents/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 3.99 | 5.77 | 5.77 | 5.85 | 5.92 |
| PSE | 2.48 | 4.14 | 4.10 | 4.11 | 4.20 |
| Generation System | 2.21 | 3.59 | 3.58 | 3.61 | 3.71 |
| **NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)** | | | | | |
| Distribution Companies | | (9.434) | (9.256) | (9.489) | (10.081) |
| PSE -- Programmed LTD | | 4.000 | 7.250 | 10.000 | 10.500 |
| Cash | | (3.769) | (6.578) | (9.007) | (11.697) |
| Generation System | | 782 | (2.387) | (4.604) | (7.995) |
| **SELF-FINANCING RATIO - %** | | | | | |
| Distribution Companies | | 132.4 | 112.7 | 105.8 | 107.9 |
| PSE | | 40.2 | 24.7 | 29.2 | 99.8 |
| **DEBT-TO-EQUITY (revalued) RATIO - %** | | | | | |
| Distribution Companies | | 0.0 | 0.0 | 0.0 | 0.0 |
| PSE | | 13.8 | 24.3 | 32.7 | 33.6 |
| Generation System | | 4.7 | 2.8 | 3.0 | 1.2 |
| **RETURN ON NET ASSETS (revalued) - %** | | | | | |
| Distribution Companies | | 0.0 | 1.5 | 2.3 | 1.7 |
| PSE | | 6.1 | 5.9 | 6.0 | 5.9 |
| Generation System | | 7.2 | 6.8 | 7.0 | 7.1 |
| **INCOME TAX FOR YEAR - billions Zl.** | | | | | |
| Distribution Companies | | 1355 | 2.172 | 2.511 | 2.363 |
| PSE | | 632 | 543 | 505 | 454 |
| Generation System | | 2895 | 2.945 | 3.255 | 3.803 |
| Total | | 4.882 | 5.660 | 6.271 | 6.620 |

NOTE: Income tax and cash position differ from the Base case in chapters 1 - 11.
This is because chapters 1 - 11 had assumed asset revaluation at December, 1992.

File : g:\pol\report\exhibit\e11-1.wk1

# Exhibit 11-2
## CONSTRAINED CASE 1
## Tariff Increase Restriction only

Assumptions:

Retail tariff increase: from mid-1992 to mid-1994, 15%; then 15% per year in real terms

Asset Revaluation: 100% of replacement cost by January 1994

Tax allowance from Depreciation: 100% of replacement cost by January 1994

Investments in generation 1993 - 1997: US$ 5.8 billion

Fixed Operation Costs: decreasing

Financial criteria for DCs: no borrowing

| | ESTIMATE | FORECAST | | | |
|---|---|---|---|---|---|
| | 1992 | 1994 | 1995 | 1996 | 1997 |
| **AVERAGE TARIFFS - Zl/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 542.1 | 623.4 | 716.9 | 795.0 | 795.0 |
| PSE | 336.7 | 438.0 | 465.0 | 545.0 | 571.0 |
| Generation System | 300.0 | 351.0 | 385.0 | 475.0 | 504.2 |
| **AVERAGE TARIFFS - US cents/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 3.99 | 4.58 | 5.27 | 5.85 | 5.85 |
| PSE | 2.48 | 3.22 | 3.42 | 4.01 | 4.20 |
| Generation System | 2.21 | 2.58 | 2.83 | 3.49 | 3.71 |
| **NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)** | | | | | |
| Distribution Companies | | (10,223) | (10,203) | (10,220) | (10,368) |
| PSE -- Programmed LTD | | 4,000 | 7,250 | 10,000 | 10,250 |
| Cash | | (4,039) | (6,968) | (9,033) | (11,654) |
| Generation System | | 14,750 | 18,582 | 18,780 | 16,041 |
| **SELF-FINANCING RATIO - %** | | | | | |
| Distribution Companies | | 114.5 | 124.7 | 111.9 | 104.0 |
| PSE | | 39.0 | 24.4 | 29.2 | 99.7 |
| **DEBT-TO-EQUITY (revalued) RATIO - %** | | | | | |
| Distribution Companies | | (7.3) | (7.0) | (6.8) | (6.7) |
| PSE | | 13.8 | 24.4 | 32.8 | 33.7 |
| Generation System | | 4.7 | 5.3 | 7.1 | 7.3 |
| **RETURN ON NET ASSETS (revalued) - %** | | | | | |
| Distribution Companies | | (2.7) | 4.8 | 3.9 | 0.7 |
| PSE | | 6.1 | 6.0 | 6.1 | 5.9 |
| Generation System | | (6.7) | (3.5) | 4.6 | 5.8 |
| **INCOME TAX FOR YEAR - billions Zl.** | | | | | |
| Distribution Companies | | 52 | 3,305 | 3,169 | 1,943 |
| PSE | | 613 | 535 | 505 | 453 |
| Generation System | | (3,655) | (2,607) | 1,037 | 1,922 |
| Total | | (2,990) | 1,233 | 4,711 | 4,318 |

NOTE: Income tax and cash position differ from the Base case in chapters 1 - 11.
This is because chapters 1 - 11 had assumed asset revaluation at December, 1992.

File : g:\pol\report\exhibit\e11-2.wk1

Exhibit 11-3

# CONSTRAINED CASE 2

## Tariff Increase Restriction and no Asset Revaluation

Assumptions:

Retail tariff increase: from mid-1992 to mid-1994, 15% ; then 15% per year in real terms

Asset Revaluation: 0% of replacement cost by January 1997

Tax allowance from Depreciation: 0% of replacement cost by January 1997

Investments in generation 1993 - 1997: US$ 5.8 billion

Fixed Operation Costs: decreasing

Financial criteria for DCs: no borrowing

| | ESTIMATE | FORECAST | | | |
|---|---|---|---|---|---|
| | 1992 | 1994 | 1995 | 1996 | 1997 |
| **AVERAGE TARIFFS - Zl/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 542.1 | 623.4 | 716.9 | 735.0 | 743.0 |
| PSE | 336.7 | 375.0 | 398.0 | 439.0 | 458.0 |
| Generation System | 300.0 | 314.0 | 338.0 | 379.0 | 393.0 |
| **AVERAGE TARIFFS - US cents/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 3.99 | 4.58 | 5.27 | 5.40 | 5.46 |
| PSE | 2.48 | 2.76 | 2.93 | 3.23 | 3.37 |
| Generation System | 2.21 | 2.31 | 2.49 | 2.79 | 2.89 |
| **NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)** | | | | | |
| Distribution Companies | | 231 | 180 | 199 | 189 |
| PSE -- Programmed LTD | | 4,000 | 7,250 | 10,000 | 10,250 |
| Cash | | | | | |
| Generation System | | 19,542 | 29,431 | 39,026 | 48,018 |
| **SELF-FINANCING RATIO - %** | | | | | |
| Distribution Companies | | 112.7 | 125.2 | 104.9 | 103.9 |
| PSE | | 10.4 | 9.2 | 14.4 | 64.3 |
| **DEBT-TO-EQUITY (revalued) RATIO - %** | | | | | |
| Distribution Companies | | 2.9 | 2.2 | 1.9 | 1.6 |
| PSE | | 53.9 | 95.0 | 127.4 | 129.5 |
| Generation System | | 61.0 | 86.3 | 111.0 | 128.3 |
| **RETURN ON NET ASSETS (revalued) - %** | | | | | |
| Distribution Companies | | 33.9 | 46.7 | 33.4 | 25.6 |
| PSE | | 5.8 | 6.6 | 6.3 | 6.4 |
| Generation System | | (13.9) | (3.4) | 5.8 | 5.4 |
| **INCOME TAX FOR YEAR - billions Zl.** | | | | | |
| Distribution Companies | | 5,955 | 9,300 | 8,448 | 7,958 |
| PSE | | 135 | 141 | 145 | 172 |
| Generation System | | (2,200) | (1,843) | (669) | (731) |
| Total | | 3,890 | 7,592 | 7,920 | 7,372 |

NOTE: Income tax and cash position differ from the Base case in chapters 1 - 11.
This is because chapters 1 - 11 had assumed asset revaluation at December, 1992.

File : g:\pol\report\exhibit\e11-3.wk1

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# Exhibit 11-4
## CONSTRAINED CASE 3
## Tariff Increase Restriction and Gradual Asset Revaluation
## ("most likely case")

Assumptions:

Retail tariff increase: from mid-1992 to mid-1994, 15% ; then 15% per year in real terms

Asset Revaluation: 100% of replacement cost by January 1997

Tax allowance from Depreciation: 70% of replacement cost by January 1997

Investments in generation 1993 - 1997: US$ 5.8 billion

Fixed Operation Costs: decreasing

Financial criteria for DCs: no borrowing

| | ESTIMATE | FORECAST | | | |
|---|---|---|---|---|---|
| | 1992 | 1994 | 1995 | 1996 | 1997 |
| **AVERAGE TARIFFS - Zl/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 542.1 | 623.4 | 716.9 | 814.0 | 814.0 |
| PSE | 336.7 | 378.0 | 411.0 | 517.0 | 567.0 |
| Generation System | 300.0 | 307.0 | 337.0 | 446.0 | 494.0 |
| **AVERAGE TARIFFS - US cents/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 3.99 | 4.58 | 5.27 | 5.99 | 5.99 |
| PSE | 2.48 | 2.78 | 3.02 | 3.80 | 4.17 |
| Generation System | 2.21 | 2.26 | 2.48 | 3.28 | 3.63 |
| **NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)** | | | | | |
| Distribution Companies | | 165 | 203 | 199 | 219 |
| PSE -- Programmed LTD | | 4.000 | 7.250 | 10.000 | 10.250 |
| Cash | | (1.738) | (2.597) | (3.429) | (5.520) |
| Generation System | | 19.942 | 29.399 | 34.032 | 34.356 |
| **SELF-FINANCING RATIO - %** | | | | | |
| Distribution Companies | | 113.3 | 124.5 | 114.0 | 103.0 |
| PSE | | 11.8 | 9.5 | 18.8 | 87.0 |
| **DEBT-TO-EQUITY (revalued) RATIO - %** | | | | | |
| Distribution Companies | | 1.8 | 1.4 | 1.1 | 1.0 |
| PSE | | 24.8 | 34.8 | 38.9 | 34.2 |
| Generation System | | 28.6 | 34.3 | 34.7 | 34.2 |
| **RETURN ON NET ASSETS (revalued) - %** | | | | | |
| Distribution Companies | | 15.1 | 18.0 | 10.8 | 2.8 |
| PSE | | 6.4 | 6.0 | 6.1 | 5.9 |
| Generation System | | (9.9) | (5.4) | 4.3 | 6.0 |
| **INCOME TAX FOR YEAR - billions Zl.** | | | | | |
| Distribution Companies | | 5.576 | 8.055 | 6.886 | 3.646 |
| PSE | | 543 | 656 | 771 | 773 |
| Generation System | | (2.664) | (2.409) | 1.245 | 2.338 |
| Total | | 3.455 | 6.302 | 8.902 | 6.757 |

NOTE: Income tax and cash position differ from the Base case in chapters 1 - 11.
This is because chapters 1 - 11 had assumed asset revaluation at December, 1992.

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This case results in significantly lower retail tariffs than any of the other cases. However, it is not deemed viable because it results in persistent annual net losses at the generating company level, as well as significant distortions in the financial ratios and financial relationships within the industry.

### Case 3 - Tariff Increase Restriction and Gradual Asset Revaluation

This is considered to be the ***most likely*** case and the results are shown in Exhibit 11-4.

In the initial years 1994 and 1995, the limited asset revaluation and consequent limited deduction of depreciation expense result in higher income tax and reduced annual cash flow. In turn this necessitates a reduced bulk purchase tariff from PSE in order to maintain the annual cash flow in the retail system.

Insofar as the PSE system is permitted a 6.0% rate of return, the burden of constrained tariffs is borne primarily by the generating system.

In 1994, the generating system incurs operating losses and net losses. A similar result occurs in 1995, leading to net borrowing by 1995 of approximately zl 30,000 billion. This is equivalent to a debt-to-equity ratio of about 34%.

A tariff of 814 zl/kwh is required to achieve a 6.0% return on net assets in 1997.

### Case 3a - High Capital Investments in the Generation System

The results of a sensitivity analysis of the results of Case 3 to higher investments in the generation system are shown in Exhibit 11-5.

All of the additional investment will require to be borrowed -- leading to an increase in net borrowing by the generating system. Net borrowing by 1997 would amount to zl 73,223 billion -- or about U.S.$5.5 billion -- equivalent to a debt-to-equity ratio of 66.8%.

As the increased investment will eventually increase the assets-in-service, the tariff charged by the generating system will increase in 1996 and 1997 to reflect a 6.0% return on net assets in service. Thus this case will result in the highest tariff in 1997 -- i.e. 846 zl/kwh, as well as the highest debt for the generating system.



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# Exhibit 11-5
## CONSTRAINED CASE 3a
## Sensitivity Analysis to High Generation Investment

Assumptions:

Retail tariff increase: from mid-1992 to mid-1994, 15%; then 15% per year in real terms

Asset Revaluation: 100% of replacement cost by January 1997

Tax allowance from Depreciation: 70% of replacement cost by January 1997

Investments in generation 1993 - 1997: US$ 9.0 billion

Fixed Operation Costs: decreasing

Financial criteria for DCs: no borrowing

| | ESTIMATE | FORECAST | | | |
|---|---|---|---|---|---|
| | 1992 | 1994 | 1995 | 1996 | 1997 |
| **AVERAGE TARIFFS - Zl/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 542.1 | 623.4 | 716.9 | 824.5 | 846.0 |
| PSE | 336.7 | 378.0 | 411.0 | 524.0 | 591.0 |
| Generation System | 300.0 | 307.0 | 337.0 | 454.0 | 520.0 |
| **AVERAGE TARIFFS - US cents/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 3.99 | 4.58 | 5.27 | 6.06 | 6.22 |
| PSE | 2.48 | 2.78 | 3.02 | 3.85 | 4.35 |
| Generation System | 2.21 | 2.26 | 2.48 | 3.34 | 3.82 |
| **NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)** | | | | | |
| Distribution Companies | | 165 | 203 | 173 | 173 |
| PSE -- Programmed LTD | | 4,000 | 7,250 | 10,000 | 10,250 |
| Cash | | (1,738) | (2,597) | (3,389) | (5,483) |
| Generation System | | 33,790 | 50,709 | 64,911 | 73,223 |
| **SELF-FINANCING RATIO - %** | | | | | |
| Distribution Companies | | 113.3 | 124.5 | 115.3 | 105.6 |
| PSE | | 12.0 | 10.0 | 20.2 | 95.0 |
| **DEBT-TO-EQUITY (revalued) RATIO - %** | | | | | |
| Distribution Companies | | 1.8 | 1.4 | 1.1 | 1.0 |
| PSE | | 24.8 | 34.8 | 38.9 | 34.1 |
| Generation System | | 44.3 | 55.8 | 61.2 | 66.8 |
| **RETURN ON NET ASSETS (revalued) - %** | | | | | |
| Distribution Companies | | 15.1 | 18.0 | 11.1 | 3.2 |
| PSE | | 6.4 | 6.0 | 6.1 | 6.3 |
| Generation System | | (9.2) | (5.1) | 3.9 | 6.0 |
| **INCOME TAX FOR YEAR - billions Zl.** | | | | | |
| Distribution Companies | | 5,576 | 8,055 | 7,030 | 3,931 |
| PSE | | 543 | 656 | 766 | 836 |
| Generation System | | (3,098) | (3,323) | 229 | 1,579 |
| Total | | 3,021 | 5,388 | 8,025 | 6,346 |

NOTE: Income tax and cash position differ from the Base case in chapters 1 - 11.
This is because chapters 1 - 11 had assumed asset revaluation at December, 1992.

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# Exhibit 11–6
## CONSTRAINED CASE 3b
## Sensitivity Analysis to Constant Operating Costs

Assumptions:

Retail tariff increase: from mid–1992 to mid–1994, 15%: then 15% per year in real terms

Asset Revaluation: 100% of replacement cost by January 1997

Tax allowance from Depreciation: 70% of replacement cost by January 1997

Investments in generation 1993 – 1997: US$ 5.8 billion

Fixed Operation Costs: constant

Financial criteria for DCs: no borrowing

| | ESTIMATE | FORECAST | | | |
|---|---|---|---|---|---|
| | 1992 | 1994 | 1995 | 1996 | 1997 |
| **AVERAGE TARIFFS – Zl/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 542.1 | 623.4 | 716.9 | 824.5 | 835.0 |
| PSE | 336.7 | 378.0 | 411.0 | 524.0 | 583.0 |
| Generation System | 300.0 | 307.0 | 337.0 | 454.0 | 511.0 |
| **AVERAGE TARIFFS – US cents/kWh (at mid 1992 price levels)** | | | | | |
| Distribution Companies | 3.99 | 4.58 | 5.27 | 6.06 | 6.14 |
| PSE | 2.48 | 2.78 | 3.02 | 3.85 | 4.29 |
| Generation System | 2.21 | 2.26 | 2.48 | 3.34 | 3.76 |
| **NET BORROWING / CASH DEFICIENCY (SURPLUS) (billions zloty)** | | | | | |
| Distribution Companies | | 165 | 203 | 173 | 154 |
| PSE -- Programmed LTD | | 4,000 | 7,250 | 10,000 | 10,250 |
| Cash | | (1,738) | (2,597) | (3,389) | (5,512) |
| Generation System | | 21,007 | 31,422 | 36,770 | 37,370 |
| **SELF–FINANCING RATIO – %** | | | | | |
| Distribution Companies | | 113.3 | 124.5 | 115.3 | 104.5 |
| PSE | | 11.8 | 9.5 | 18.6 | 94.0 |
| **DEBT–TO–EQUITY (revalued) RATIO – %** | | | | | |
| Distribution Companies | | 1.8 | 1.4 | 1.1 | 1.0 |
| PSE | | 24.8 | 34.8 | 38.9 | 34.1 |
| Generation System | | 30.2 | 37.0 | 37.7 | 37.4 |
| **RETURN ON NET ASSETS (revalued) – %** | | | | | |
| Distribution Companies | | 15.1 | 18.0 | 11.1 | 3.0 |
| PSE | | 6.4 | 6.0 | 6.1 | 6.3 |
| Generation System | | (11.5) | (6.9) | 3.5 | 6.0 |
| **INCOME TAX FOR YEAR – billions Zl.** | | | | | |
| Distribution Companies | | 5,576 | 8,055 | 7,030 | 3,806 |
| PSE | | 543 | 656 | 766 | 829 |
| Generation System | | (3,118) | (3,054) | 798 | 2,188 |
| Total | | 3,001 | 5,657 | 8,594 | 6,823 |

NOTE: Income tax and cash position differ from the Base case in chapters 1 – 11.
This is because chapters 1 – 11 had assumed asset revaluation at December, 1992.

File : g:\pol\report\exhibit\e11–6.wk1

### Case 3b - High Operating Costs in the Generation System

In Exhibit 11-6 are shown the results of Case 3 modified to reflect fixed costs being maintained at 1992 levels, rather than decreasing.

The result is a retail tariff of 835 zl/kwh in 1997 -- or about 2.5% higher than in Case 3.

## 11.4 CONCLUSIONS OF THE CONSTRAINED FINANCIAL ANALYSIS

### 11.4.1 Tariffs at retail level

With the exception of Case 2, which is essentially not financially viable, it can be seen in Exhibit 11-7 that by 1997 the retail tariff falls in the range 795 to 846 zl/kwh, or within -2.5% to +3.5% of the 814 zl/kwh in the recommended Case 3.

**EXHIBIT 11-7**

**AVERAGE RETAIL TARIFFS – ZL/KWH AT MID-1992 PRICE LEVEL**

| | 1992 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|
| Non-constrained | 542.1 | 785.0 | 785.0 | 795.0 | 805.0 |
| Case 1 | | 623.4 | 716.9 | 795.0 | 795.0 |
| 2 | | 623.4 | 716.9 | 735.0 | 743.0 |
| **3** | | **623.4** | **716.9** | **814.0** | **814.0** |
| 3A | | 623.4 | 716.9 | 824.5 | 846.0 |
| 3B | | 623.4 | 716.9 | 824.5 | 835.0 |

### 11.4.2 Debt

Except for Case 2, none of the alternatives results in an unacceptable debt-to-equity ratio. Even so, it should be recognized that the debt to be incurred is the result of not implementing the tariff increases recommended in the unconstrained case.

It should also be noted that the net cash deficiency of zl 73,223 billion in Case 3A would be likely to require further future tariff increases in order to amortise the principal.

### 11.4.3 Income tax

The total income tax payable in each case is summarized in Exhibit 11-8.

**EXHIBIT 11-8**

**INCOME TAX PAYABLE (b1.Z1. at mid 1992 price levels).**

| | 1994 | 1995 | 1996 | 1997 | TOTAL |
|---|---|---|---|---|---|
| Non-constrained | 4,882 | 5,660 | 6,271 | 6,620 | 23,433 |
| Case 1 | (2,990) | 1,233 | 4,711 | 4,318 | 7,272 |
| 2 | 3,890 | 7,592 | 7,920 | 7,372 | 26,774 |
| **3** | **3,445** | **6,302** | **8,902** | **6,757** | **25,406** |
| 3A | 3,021 | 5,388 | 8,025 | 6,346 | 22,780 |
| 3B | 3,001 | 5,657 | 8,594 | 6,823 | 24,075 |

With the exception of Case 1 which combines restricted tariff increases with the maximum depreciation allowance for tax, all other cases result in similar tax yields.

However, it should be noted that Case 2, which yields the highest tax revenue, is also not viable financially. It is the reverse of Case 1, in that it combines the lowest tariffs with the highest taxes (resulting from the lowest depreciation allowance due to the assets not being revalued).

Thus the overall conclusion is that allowing the industry to operate on an economic base with properly valued assets and appropriate tariffs is unlikely to materially affect the total income tax yield from the industry.

### 11.4.4 Consolidated Financial Statements

The consolidated financial statements of the generating companies, PSE and the distribution companies corresponding to the most likely scenario, Case 3, are shown in Exhibits 11-9 to 11-17. These can be compared to the consolidated financial statements corresponding to the unconstrained case for generation companies, PSE and distribution companies included in Chapters 5, 8 and 9 respectively.

## Exhibit 11 – 9
## Case 3
## CONSOLIDATED BALANCE SHEET – GENERATING COMPANIES

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **ASSETS** | | | | | | |
| | 538 | 929 | Cash | 1,583 | 745 | 787 | 885 | 1,199 | 1,355 |
| | 374 | 1,378 | Accounts Receivable | 1,594 | 1,584 | 1,677 | 1,891 | 2,580 | 2,922 |
| | 797 | 1,614 | Inventories -- Fuel | 1,694 | 3,171 | 3,334 | 3,414 | 3,547 | 3,630 |
| | 12 | 20 | Others | | | | | | |
| | 468 | 224 | Others | | 450 | 850 | 1,300 | 1,700 | 2,000 |
| | **2,190** | **4,165** | **Total Current Assets** | **4,871** | **5,950** | **6,647** | **7,490** | **9,027** | **9,907** |
| | 35,125 | 36,835 | Gross Fixed Assets | 73,272 | 109,924 | 165,632 | 211,220 | 267,422 | 297,728 |
| | 16,435 | 18,295 | Less: Acc. Depreciation | 38,553 | 60,025 | 82,719 | 107,270 | 133,340 | 142,254 |
| | 18,690 | 18,539 | Net Fixed Assets | 34,719 | 49,899 | 82,914 | 103,950 | 134,082 | 155,474 |
| | 1,413 | 18,735 | Capital Work-in-Progress | 23,133 | 33,446 | 27,611 | 30,368 | 26,257 | 9,738 |
| | **22,293** | **41,439** | **TOTAL ASSETS EMPLOYED** | **62,724** | **89,295** | **117,171** | **141,809** | **169,366** | **175,118** |
| | | | **LIABILITIES** | | | | | | |
| | 602 | 1,329 | Accounts Payable | | | | | | |
| | 556 | 920 | Other Liabilities | | | | | | |
| | | | LTD due within 1 year – existing | 170 | 170 | 170 | 170 | 170 | 170 |
| | 10 | 18 | LTD due within 1 year – new local | | | | | | |
| | | | LTD due within 1 year – new FX | | | | | | |
| | | | Cash Deficiency (Surplus) | (2,135) | 7,782 | 19,942 | 29,399 | 34,032 | 34,356 |
| | **1,168** | **2,268** | **Total Current Liabilities** | **(1,965)** | **7,952** | **20,286** | **30,022** | **35,050** | **35,774** |
| | | (50) | Other Liabilities | | | | | | |
| | 1,447 | 2,492 | Long Term Debt – existing | 3,068 | 2,899 | 2,729 | 2,559 | 2,390 | 2,220 |
| | | 162 | Long Term Debt – new local | 704 | 1,970 | 3,342 | 4,112 | 6,934 | 7,725 |
| | | | Long Term Debt – new FX | | | | | | |
| | **1,447** | **2,654** | **Total Long Term Debt** | **3,772** | **4,869** | **6,071** | **6,671** | **9,323** | **9,945** |
| | | | **Equity Balance:** | | | | | | |
| | 14,657 | 15,642 | Assumed Opening Position | 32,770 | 32,770 | 32,770 | 32,770 | 32,770 | 32,770 |
| | 1,199 | 16,751 | Additional Paid in Capital | 2,718 | 5,436 | 8,230 | 10,870 | 13,589 | 16,306 |
| | 482 | 378 | Revaluation of Fixed Assets | 17,408 | 35,014 | 52,620 | 70,226 | 87,832 | 87,832 |
| | 2,833 | 3,103 | Retained Earnings -- Prior Years | 3,797 | 8,021 | 3,255 | (2,756) | (8,751) | (9,204) |
| | 507 | 694 | Current Year's Net Income | 4,223 | (4,766) | (6,011) | (5,995) | (453) | 1,675 |
| | **19,678** | **36,567** | **Total Equity** | **60,916** | **76,475** | **90,864** | **105,115** | **124,987** | **129,379** |
| | **22,293** | **41,439** | **TOTAL LIABILITIES & EQUITY** | **62,724** | **89,295** | **117,171** | **141,809** | **169,366** | **175,118** |

Billions Zloty at Base Year Prices

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Exhibit 11 – 10
Case 3
CONSOLIDATED BALANCE SHEET – POLSKIE SIECI ELEKTROENERGETYCZNE

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **ASSETS** | | | | | | |
| | | | Fixed Assets: | | | | | | |
| | | | Capital Assets | | | | | | |
| | 179 | 180 | Gross Fixed Assets | 180 | 680 | 1,680 | 4,180 | 8,180 | 12,180 |
| | | | Plus: Transfers of Grid from DCs | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 |
| | | | Plus: Transfers of Pumped Storage | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 |
| | | | **Total Adjusted Gross Fixed Assets** | **10,685** | **11,185** | **12,185** | **14,685** | **18,685** | **22,685** |
| | | | Plus: Revaluation to 1992 | | 9,349 | 18,698 | 28,046 | 37,397 | 46,746 |
| | | | Plus: Revaluation after 1992 | | | | | | |
| | | | Revalued Gross Fixed Assets | 10,685 | 20,534 | 30,883 | 42,733 | 56,082 | 69,431 |
| | 91 | 95 | Less: Accumulated Depreciat'n | 110 | 132 | 191 | 337 | 646 | 1,155 |
| | | | Depreciation on Transfers | 5,483 | 6,008 | 6,533 | 7,059 | 7,584 | 8,109 |
| | | | Revalued Depreciation | | 4,880 | 9,760 | 14,639 | 19,519 | 24,399 |
| | | | Depreciation on Revaluation | | 234 | 935 | 2,104 | 3,740 | 5,843 |
| | | | **Total Accumulated Depreciation** | **29,810** | **32,685** | **35,607** | **38,616** | **41,787** | **45,159** |
| | 88 | 85 | Net Fixed Assets | 5,092 | 9,281 | 13,465 | 18,594 | 24,593 | 29,924 |
| | 3 | 130 | Capital Work-in-Progress | 699 | 1,344 | 3,000 | 4,723 | 4,695 | 2,627 |
| | 1 | 185 | Advance Payments | 197 | 197 | 197 | 197 | 197 | 197 |
| | | 1 | Patents & Licenses | 1 | 1 | 1 | 1 | 1 | 1 |
| | | | **Financial Investments:** | | | | | | |
| | | 0 | Shares in other Companies | | | | | | |
| | 221 | 193 | Long Term Accounts Receivable | 193 | 193 | 193 | 193 | 193 | 193 |
| | | | **Current Assets:** | | | | | | |
| | 0 | 0 | Inventories | | | | | | |
| | 247 | 1,905 | Accounts Receivable | 2,736 | 2,788 | 3,195 | 3,584 | 4,630 | 5,218 |
| | 24 | 0 | Income Tax Receivable | | | | | | |
| | 5 | 5 | Other Accounts Receivable | | | | | | |
| | 590 | 25 | Cash at Bank and on Deposit | 15 | 315 | 1,738 | 2,597 | 3,429 | 5,520 |
| | 868 | 1,936 | **Total Current Assets** | **2,751** | **3,103** | **4,933** | **6,181** | **8,059** | **10,738** |
| | 1,180 | 2,530 | **TOTAL ASSETS** | **8,934** | **14,119** | **21,790** | **29,889** | **37,939** | **43,681** |

## Exhibit 11-10
## Case 3
## CONSOLIDATED BALANCE SHEET – POLSKIE SIECI ELEKTROENERGETYCZNE

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **LIABILITIES** | | | | | | |
| | | | **Equity Capital:** | | | | | | |
| | 515 | 515 | Equity | 515 | 515 | 515 | 515 | 515 | 515 |
| | 71 | 389 | Reserve Capital | 610 | 1,165 | 1,447 | 1,682 | 1,906 | 2,265 |
| | | | Transfers of Grid from DCs | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 |
| | | | Transfer of Pumped Storage | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 |
| | | | Less: Accum. dep'n on Transfers | 5,483 | 5,483 | 5,483 | 5,483 | 5,483 | 5,483 |
| | 1 | | Asset Revaluation | 0 | 4,469 | 8,939 | 13,408 | 17,878 | 22,347 |
| | 321 | 221 | Current Year's Net Income | 555 | 281 | 236 | 224 | 379 | 529 |
| | 906 | 1,125 | **Total Equity** | 6,702 | 11,453 | 16,158 | 20,851 | 25,699 | 30,697 |
| | | 315 | Long Term Debt | 750 | 1,200 | 4,000 | 7,250 | 10,000 | 10,500 |
| | | | **Current Liabilities:** | | | | | | |
| | 231 | 841 | Accounts Payable | 1,232 | 1,217 | 1,382 | 1,538 | 1,990 | 2,234 |
| | 6 | 112 | Other Accounts Payable | 110 | 110 | 110 | 110 | 110 | 110 |
| | | | Short Term Loans | | | | | | |
| | 35 | 138 | Other Liabilities | 140 | 140 | 140 | 140 | 140 | 140 |
| | | | Owing to Bank | | | | | | |
| | 271 | 1,091 | **Total Current Liabilities** | 1,482 | 1,467 | 1,632 | 1,788 | 2,240 | 2,484 |
| | 1,180 | 2,531 | **TOTAL LIABILITIES** | 8,934 | 14,119 | 21,790 | 29,889 | 37,939 | 43,681 |
| | 179 | 180 | Gross Fixed Assets | 180 | 680 | 1,680 | 4,180 | 8,180 | 12,180 |
| | 6,903 | 6,903 | Plus: Transfers of Grid from DCs | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 | 7,165 |
| | | 3,252 | Plus: Transfers of Pumped Storage | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 | 3,339 |
| | 7,082 | 7,084 | **Total Adjusted Gross Fixed Assets** | 10,685 | 11,185 | 12,185 | 14,685 | 18,685 | 22,685 |

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.
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## Exhibit 11-11
## Case 3
## CONSOLIDATED BALANCE SHEET – DISTRIBUTION COMPANIES

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **ASSETS** | | | | | | |
| | 1,116 | 1,226 | Cash | 1,692 | 1,692 | 1,692 | 1,692 | 1,692 | 1,692 |
| | 895 | 3,716 | Accounts Receivable | 8,719 | 8,948 | 10,593 | 12,674 | 14,764 | 15,168 |
| | 318 | 532 | Inventories -- Fuel | 735 | 735 | 735 | 735 | 735 | 735 |
| | 2,329 | 5,474 | **Total Current Assets** | 11,145 | 11,375 | 13,019 | 15,101 | 17,191 | 17,595 |
| | | | Gross Fixed Assets: | 73,272 | 109,924 | 165,632 | 211,220 | 267,422 | 297,728 |
| | | 6,903 | Transmission (>110kv)& S/stations | | | | | | |
| | | 44,206 | Distribution Lines | | | | | | |
| | | 14,803 | Substations | | | | | | |
| | | 4,930 | Other Fixed & Tangible Assets | | | | | | |
| | 65,818 | 70,842 | Gross Fixed & Tangible Assets | 63,939 | 103,009 | 145,561 | 192,403 | 244,170 | 296,564 |
| | 33,859 | 36,976 | Less: Acc. Depreciation | 36,553 | 60,025 | 82,719 | 107,270 | 133,340 | 142,254 |
| | 31,959 | 33,866 | Net Fixed & Tangible Assets | 27,369 | 42,556 | 59,272 | 78,149 | 99,610 | 119,110 |
| | 1,190 | 2,903 | Capital Work-in-Progress | 2,903 | 6,385 | 10,674 | 15,600 | 16,227 | 16,369 |
| | 6 | 30 | Goodwill | | | | | | |
| | 34,927 | 42,272 | **TOTAL ASSETS EMPLOYED** | 41,417 | 60,316 | 82,965 | 108,849 | 133,028 | 153,094 |
| | | | **LIABILITIES** | | | | | | |
| | 891 | 2,671 | Accounts Payable | | | | | | |
| | 633 | 3,799 | Other Liabilities | | | | | | |
| | | | Cash Deficiency (Surplus) | 2,820 | 186 | 165 | 203 | 199 | 219 |
| | 1,784 | 6,470 | **Total Current Liabilities** | 2,820 | 186 | 165 | 203 | 199 | 219 |
| | 575 | 1,309 | Long Term Debt | 1,309 | 1,309 | 1,309 | 1,309 | 1,309 | 1,309 |
| | 575 | 1,309 | **Total Long Term Debt** | 1,309 | 1,309 | 1,309 | 1,309 | 1,309 | 1,309 |
| | | | Equity Balance: | | | | | | |
| | 31,645 | 32,578 | Assumed Opening Position | 32,578 | 32,578 | 32,578 | 32,578 | 32,578 | 32,578 |
| | | | Reserve for Asset Revaluation | 0 | 17,290 | 34,579 | 51,869 | 69,159 | 86,448 |
| | | 923 | Retained Earnings -- Prior Years | 1,915 | 4,710 | 8,953 | 14,334 | 22,690 | 29,784 |
| | 923 | 991 | Current Year's Net Income | 2,795 | 4,243 | 5,381 | 8,556 | 6,894 | 2,756 |
| | 32,568 | 34,492 | **Total Equity** | 37,288 | 58,820 | 81,491 | 107,337 | 131,520 | 151,565 |
| | 34,927 | 42,272 | **TOTAL LIABILITIES & EQUITY** | 41,417 | 60,316 | 82,965 | 108,849 | 133,028 | 153,094 |

Billions Zloty at Base Year Prices

RCG/HAGLER, BAILLY, Inc.
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## Exhibit 11 – 12
## Case 3
## INCOME STATEMENT – GENERATING COMPANIES

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | 97,847 | Energy Sales -- GWh | 97,011 | 96,337 | 99,676 | 102,424 | 105,582 | 107,948 |
| | | 20,773 | Capacity -- MW | 20,476 | 20,366 | 20,180 | 20,390 | 20,189 | 21,316 |
| | | | % Capacity Sold | | | | | | |
| | | 73,135 | Hours of Production/Year | 73,626 | 73,626 | 74,765 | 75,904 | 66,791 | 60,630 |
| | | 195,312 | Capacity Sales – MW/m | 185,803 | 182,381 | 184,205 | 184,127 | 172,483 | 173,497 |
| | | | Max Capacity Sales @1994 Installation | 208,851 | 207,732 | 202,166 | 200,636 | 191,242 | 195,389 |
| | | 115.499 | Energy Sales Price -- Zl/kWh | 196.754 | 300.222 | 306.771 | 313.057 | 326.149 | 338.126 |
| | | 45,459 | Capacity Price -- '000 Zl/MW/m | 53,884 | 103,053 | 96,580 | 96,867 | 100,644 | 103,333 |
| | | | Adjusted 1994 Capacity Price | | | | | | |
| | | | Sales Revenue | | | | | | |
| | | 11,301 | Energy | 19,087 | 28,922 | 30,578 | 32,064 | 34,435 | 36,500 |
| | | 8,879 | Capacity | 10,012 | 18,795 | 18,159 | 17,836 | 17,359 | 17,928 |
| 282 | 3,698 | 20,180 | Sub-total Electricity Sales | 29,099 | 28,901 | 30,801 | 34,517 | 47,089 | 53,327 |
| 18 | 320 | 412 | Others | 1,012 | 885 | 875 | 875 | 875 | 855 |
| **300** | **4,018** | **20,592** | **Total Sales/Revenues** | **30,111** | **29,786** | **31,475** | **35,391** | **47,964** | **54,181** |
| | | | **Variable Cost** | | | | | | |
| 170 | 2,087 | 10,738 | Fuel | 11,592 | 25,295 | 26,245 | 27,016 | 28,018 | 28,757 |
| | 88 | | Transport | 1,694 | | | | | |
| | 49 | 601 | Environmental Penalty | 2,719 | 2,687 | 2,742 | 2,798 | 2,850 | 2,871 |
| 3 | 28 | 4 | Others | | | | | | |
| 173 | 2,253 | 11,343 | Total Variable Cost @ 1992 Prices | 16,004 | 27,982 | 28,987 | 29,815 | 30,868 | 31,628 |
| | | | Plus: Inflation | | | | | | |
| **173** | **2,253** | **11,343** | **Total Variable Cost** | **16,004** | **27,982** | **28,987** | **29,815** | **30,868** | **31,628** |
| | | | **Fixed/ Capacity Costs** | | | | | | |
| 95 | 951 | 5,865 | Existing Plant | 6,398 | 5,778 | 5,342 | 4,956 | 4,695 | 4,501 |
| | | | New Plant | | | 72 | 145 | 289 | 434 |
| 95 | 951 | 5,865 | Total Fixed Cost (ex.Dep'n)@1992 | 6,398 | 5,778 | 5,415 | 5,101 | 4,984 | 4,935 |
| | | | Plus: Inflation | | | | | | |
| **95** | **951** | **5,865** | **Total Fixed Cost before Dep'n.** | **6,398** | **5,778** | **5,415** | **5,101** | **4,984** | **4,935** |
| 7 | 141 | 1,947 | Depreciation Expense | 1,226 | 2,442 | 3,664 | 5,521 | 7,041 | 8,914 |
| 274 | 3,344 | 19,155 | Total Operating Expense | 23,629 | 36,203 | 38,066 | 40,437 | 42,893 | 45,477 |
| 26 | 674 | 1,436 | Operating Income | 6,482 | (6,417) | (6,591) | (5,045) | 5,071 | 8,704 |
| 4 | 31 | 65 | Financial/Interest Expense (Net) | (557) | 711 | 2,084 | 3,359 | 4,279 | 4,691 |
| 0 | (67) | 421 | Extraordinary Income (Loss) | | | | | | |
| 23 | 575 | 1,794 | Income Before Tax | 7,039 | (7,129) | (8,675) | (8,405) | 792 | 4,013 |
| 5 | 279 | 980 | Corporate Tax | 2,816 | (2,363) | (2,664) | (2,409) | 1,245 | 2,338 |
| 18 | 296 | 814 | Net Income After Tax | 4,223 | (4,766) | (6,011) | (5,995) | (453) | 1,675 |

Billions Zloty at Base Year Prices

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Exhibit 11 – 13
Case 3
INCOME STATEMENT – POLSKIE SIECI ELEKTROENERGETYCZNE

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | INCOME STATEMENT | | | | | | |
| | | 24,653 | Total Sales | 35,662 | 36,340 | 41,655 | 46,723 | 60,354 | 68,018 |
| | | 24,015 | Total Cost of Sales | 34,329 | 34,161 | 38,804 | 43,191 | 55,675 | 62,720 |
| | | 638 | Net Revenue from Energy Sales | 1,333 | 2,179 | 2,851 | 3,531 | 4,479 | 5,298 |
| | | 141 | Materials & Energy | 166 | | | | | |
| | | 147 | Outside Services | 94 | | | | | |
| | | 35 | Salaries / Payroll | 62 | | | | | |
| | | 22 | Payroll Taxes, etc. | 30 | | | | | |
| | | 2 | Business Travel | 2 | | | | | |
| | | 7 | Other | | | | | | |
| | | 354 | Total Overhead Costs @1992 Prices | 354 | | | | | |
| | | | Inflation | | | | | | |
| | | | Total @ Current Prices | 354 | | | | | |
| | | | Plus: Transfers from Distribution Companies: | | | | | | |
| | | 9 | Materials & Energy | 12 | | | | | |
| | | 54 | Outside Services | 75 | | | | | |
| | | 39 | Salaries / Payroll | 54 | | | | | |
| | | | Payroll Taxes, etc. | | | | | | |
| | | | Business Travel | | | | | | |
| | | 56 | Pumped Storage Costs | 69 | | | | | |
| | | 143 | Other | 196 | | | | | |
| | | 301 | Total O'head Costs Transf'd @1992 Prices | 407 | | | | | |
| | | | Inflation | | | | | | |
| | | | Total O'head Costs Transferred | 407 | | | | | |
| | | | Adjusted Total Overhead Costs: | | | | | | |
| | | 150 | Materials & Energy | 176 | 176 | 176 | 176 | 176 | 176 |
| | | 201 | Outside Services | 169 | 169 | 169 | 169 | 169 | 169 |
| | | 74 | Salaries / Payroll | 116 | 116 | 116 | 116 | 116 | 116 |
| | | 22 | Payroll Taxes, etc. | 30 | 30 | 30 | 30 | 30 | 30 |
| | | 2 | Business Travel | 2 | 2 | 2 | 2 | 2 | 2 |
| | | 64 | Pumped Storage Costs | 69 | 69 | 69 | 69 | 69 | 69 |
| | | 151 | Other | 196 | 196 | 196 | 196 | 196 | 196 |
| | | 662 | Total Adjusted O'head Costs @1992 | 761 | 761 | 761 | 761 | 761 | 761 |
| | | | Inflation | | | | | | |
| | | | Total @ Current Prices | 761 | 761 | 761 | 761 | 761 | 761 |
| | | 13 | Other Costs | | | | | | |
| | | 271 | Net Revenue from Production | 979 | | | | | |

Exhibit 11-13
Case 3
INCOME STATEMENT – POLSKIE SIECI ELEKTROENERGETYCZNE (cont.)

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLSKIE SIECI ELEKTROENERGETYCZNE Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | (BEFORE TRANSFERRED COSTS) | | | | | | |
| | | | Net Revenue from Production | | 1,416 | 2,089 | 2,770 | 3,716 | 4,537 |
| | | | (AFTER TRANSFERRED COSTS) | | | | | | |
| | | 10 | Interest from loans to Others | | | | | | |
| | | 130 | Interest on Deposits at Bank | 2 | 18 | 113 | 238 | 331 | 492 |
| | | 2 | Gain on Currency Exchange | | | | | | |
| | | 142 | **Financial Income/ Interest Income** | 2 | 18 | 113 | 238 | 331 | 492 |
| | | 1 | Other Revenues | 17 | | | | | |
| | | 414 | Operating Income | 998 | | | | | |
| | | | (BEFORE TRANSFERRED COSTS) | | | | | | |
| | | | Operating Income | | 1,436 | 2,202 | 3,008 | 4,049 | 5,029 |
| | | | (AFTER TRANSFERRED COSTS) | | | | | | |
| | | 11 | Depreciation -- per Statement | 15 | 22 | 59 | 147 | 309 | 509 |
| | | | Plus: Dep'n on Revaluation | | | | | | |
| | | | **Total Dep'n @ Current Prices** | 15 | 22 | 59 | 147 | 309 | 509 |
| | | 469 | Depreciation -- Transferred from DCs | | 525 | 525 | 525 | 525 | 525 |
| | | | Plus: Dep'n on Revaluation | | 234 | 701 | 1,169 | 1,636 | 2,104 |
| | | | **Total Dep'n @ Current Prices** | | 759 | 1,226 | 1,694 | 2,161 | 2,629 |
| | | 480 | Total Adjusted Depreciation @1992 | 15 | 547 | 584 | 672 | 834 | 1,034 |
| | | | Plus: Dep'n on Revaluation | | 234 | 701 | 1,169 | 1,636 | 2,104 |
| | | | **Total Dep'n @ Current Prices** | 15 | 780 | 1,285 | 1,840 | 2,470 | 3,138 |
| | | | Operating Income after Deprec'n | 983 | 655 | 917 | 1,168 | 1,579 | 1,891 |
| | | | **Financial Charges:** | | | | | | |
| | | 6 | Lease Payments | | | | | | |
| | | 27 | Long Term Loan Interest | 59 | 107 | 286 | 619 | 949 | 1,128 |
| | | | Less: Interest during Construction | | 77 | 148 | 330 | 520 | 538 |
| | | | Net Interest | 59 | 30 | 138 | 289 | 429 | 589 |
| | | 371 | Income before Tax | 925 | 625 | 779 | 879 | 1,150 | 1,302 |
| | | 148 | Income Tax | 370 | 343 | 543 | 656 | 771 | 773 |
| | | | Capital Tax | | | | | | |
| | | 1 | Other Taxes | | | | | | |
| | | 221 | **NET INCOME (BEFORE TRANSFERS)** | 555 | 281 | 236 | 224 | 379 | 529 |

Billions Zloty at Base Year Prices

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Case 3

# INCOME STATEMENT – DISTRIBUTION COMPANIES

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| 111,072 | 102,508 | 96,383 | Energy Sales -- GWh | 95,074 | 97,575 | 100,441 | 104,501 | 107,220 | 110,154 |
| 19.9 | 213.4 | 354.0 | Average Tariff -- Zl/kWh | 542.1 | 542.1 | 717.0 | 824.5 | 948.2 | 1090.4 |
| 2,215 | 21,880 | 34,119 | Total Energy Sales Revenue | 51,540 | 52,895 | 62,616 | 74,920 | 87,277 | 89,665 |
| 16 | 332 | 676 | Other Revenues (Net) | 773 | 793 | 939 | 1,124 | 1,309 | 1,345 |
| **2,231** | **22,212** | **34,795** | **Total Sales/Revenues** | **52,313** | **53,689** | **63,556** | **76,043** | **88,586** | **91,010** |
| | | | **Energy Costs** | | | | | | |
| | | 130 | Own Thermal | | | | | | |
| | | 248 | Own Hydro | | | | | | |
| | | 50 | Auto producer | 58 | 58 | 58 | 58 | 58 | 58 |
| | | 7 | Small Hydro | | | | | | |
| 1,530 | 15,122 | 23,715 | PSE | 35,989 | 36,341 | 41,653 | 46,724 | 60,356 | 67,898 |
| **1,530** | **15,114** | **24,149** | **Total Energy Costs** | **36,047** | **36,399** | **41,712** | **46,783** | **60,414** | **67,956** |
| | | | **Transmission and Customer Service** | | | | | | |
| 25 | 216 | 317 | Materials | | | | | | |
| 137 | 1,422 | 1,593 | Repairs | | | | | | |
| 243 | 1,275 | 2,090 | Salaries and Payroll Taxes | | | | | | |
| 61 | 1,192 | 3,418 | Amortization | | | | | | |
| 115 | 688 | 299 | Administration Overhhead | | | | | | |
| | | | Other Costs | | | | | | |
| **581** | **4,793** | **7,717** | **Total Fixed Operating Costs** | | | | | | |
| | | | Less: High Voltage Network Costs | | | | | | |
| | 4 | 9 | Materials | | | | | | |
| | 44 | 54 | Repairs | | | | | | |
| | 26 | 39 | Salaries and Taxes | | | | | | |
| | 146 | 469 | Amortization | | | | | | |
| | 53 | 87 | Administration Overhhead | | | | | | |
| | 30 | 56 | Other Costs | | | | | | |
| | **303** | **714** | **Total High Voltage Network Costs** | | | | | | |
| | | | Net Distribution Network Costs | | | | | | |
| | 212 | 308 | Materials | 425 | 425 | 425 | 425 | 425 | 425 |
| | 1,378 | 1,539 | Repairs | 2,123 | 2,123 | 2,123 | 2,123 | 2,123 | 2,123 |
| | 1,249 | 2,051 | Salaries and Taxes | 1,732 | 1,732 | 1,732 | 1,732 | 1,732 | 1,732 |
| | 1,047 | 2,949 | Amortization | 3,197 | 5,005 | 6,959 | 9,086 | 11,429 | 14,017 |
| | 635 | 212 | Administration Overhhead | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 | 1,391 |
| | (30) | (56) | Other Costs | (78) | (78) | (78) | (78) | (78) | (78) |
| | **4,490** | **7,002** | **Total Distribution Costs @1992** | **8,790** | **10,599** | **12,552** | **14,680** | **17,022** | **19,610** |
| | | | Plus: Inflation | 0 | 0 | 0 | 0 | 0 | 0 |
| | | | **Total Distribution Costs** | **8,790** | **10,599** | **12,552** | **14,680** | **17,022** | **19,610** |
| **2,111** | **19,907** | **31,866** | **TOTAL COSTS** | **44,838** | **46,998** | **54,264** | **61,463** | **77,436** | **87,567** |
| **119** | **2,305** | **2,929** | **OPERATING INCOME** | **7,475** | **6,691** | **9,292** | **14,581** | **11,150** | **3,444** |
| **21** | **347** | **1,375** | **OTHER INCOME** | **1,581** | **1,597** | **1,830** | **2,052** | **2,650** | **2,961** |
| **2** | **5** | **260** | Interest Expense | 155 | 10 | 164 | 21 | 20 | 23 |
| **139** | **2,647** | **4,044** | **INCOME BEFORE TAX** | **8,901** | **8,277** | **10,957** | **16,611** | **13,780** | **6,401** |
| **39** | **1,716** | **2,874** | Less: Income & Corporate Tax | 6,106 | 4,034 | 5,576 | 8,055 | 6,886 | 3,646 |
| **100** | **931** | **1,170** | **NET INCOME** | **2,795** | **4,243** | **5,381** | **8,556** | **6,894** | **2,756** |

Billions Zloty at Base Year Prices

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# Exhibit 11-15
## CASE 3
## OPERATING AND FINANCIAL RATIOS – GENERATION COMPANIES

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH GENERATING COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES** | | | | | | |
| | | | Energy Sales(Gwh) – Annual Growth – % | -0.9% | -0.7% | 3.5% | 2.6% | 3.1% | 2.2% |
| | 1209.5% | 445.7% | Sales Revenue(Zl) – Annual Growth – % | 44.2% | -0.7% | 5.9% | 12.8% | 36.4% | 13.2% |
| | | 206.239 | Average Tariff -- Zlotys/kWh | 299.957 | 300.000 | 307.000 | 337.000 | 446.000 | 494.000 |
| | | | **OPERATING RATIOS** | | | | | | |
| | | 115.929 | Variable Cost / kWh | 164.969 | 290.460 | 290.815 | 291.091 | 292.358 | 292.992 |
| | | 195.761 | Total Operating Cost/ kWh | 243.575 | 375.795 | 381.899 | 394.796 | 406.252 | 421.286 |
| | | 196.428 | Total Cost/ kwh (excl. ROE) | 237.631 | 375.795 | 381.899 | 394.796 | 406.252 | 421.286 |
| | | 30,027 | Fixed Cost/ Mw/m | 34,434 | 31,684 | 29,395 | 27,702 | 28,898 | 28,445 |
| | | 39,994 | Fixed Cost plus Dep'n/ Mw/m | 41,042 | 45,075 | 49,287 | 57,688 | 69,717 | 79,824 |
| | | 40,328 | Fixed Cost plus Dep'n & Int./Mw/m | 38,042 | 45,075 | 49,287 | 57,688 | 69,717 | 79,824 |
| | 16.8% | 7.0% | Operating Income to Sales – % | 21.5% | -21.5% | -20.9% | -14.3% | 10.6% | 16.1% |
| | | | Operating Income to Gross Assets | | | | | | |
| | | | in Service (Average) – %: | | | | | | |
| | | 14.9% | –historical | | | | | | |
| | 3.8% | 4.0% | –revalued | 11.8% | -7.0% | -4.8% | -2.7% | 2.1% | 3.1% |
| | 7.2% | 7.7% | Operating Income/ Net Assets – % | 24.3% | -15.2% | -9.9% | -5.4% | 4.3% | 6.0% |
| | | | **BALANCE SHEET RATIOS** | | | | | | |
| | | 1.8 | Current Ratio | -2.5 | 0.7 | 0.3 | 0.2 | 0.3 | 0.3 |
| | | 0.5 | Cash at Bank to Sales – months | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| | | 24 | Accts.Receivable to Sales – days | 19 | 19 | 19 | 20 | 20 | 20 |
| | | | Debt to Equity Ratio – % | | | | | | |
| | | | –historical | | | | | | |
| | | 7.3% | –revalued | 6.2% | 16.5% | 28.6% | 34.3% | 34.7% | 34.2% |

Billions Zloty at Base Year Prices

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## Exhibit 11-16
## CASE 3
## OPERATING AND FINANCIAL RATIOS – PSE

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | PSE Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES** | | | | | | |
| | | -2.2% | Energy Sales(Gwh) - Annual Growth - % | -2.6% | 1.8% | 2.2% | 3.2% | 2.7% | 2.8% |
| | | | Sales Revenue(Zl) - Annual Growth - % | 50.3% | 1.9% | 14.6% | 12.2% | 29.2% | 12.7% |
| | | 218.2 | Average Tariff -- Zlotys/kWh | 336.7 | 337.0 | 378.0 | 411.0 | 517.0 | 567.0 |
| | | 218.2 | Average Energy Tariff -- Zlotys/kWh | 336.7 | 337.0 | 378.0 | 411.0 | 517.0 | 567.0 |
| | | | Average Capacity Tariff '000 Zlotys/ MW/mo | | | | | | |
| | | | **INCOME RATIOS:** | | | | | | |
| | | | Operating Income/ Net Assets - % | | | | | | |
| | | 145.7% | BEFORE Transfer of Assets/Costs | 200.0% | | | | | |
| | | -7.2% | AFTER Transfer of Assets/Costs | 20.0% | 6.6% | 6.4% | 6.0% | 6.1% | 5.9% |
| | | | Operating Income after Dep'n/ Sales - % | | | | | | |
| | | 1.1% | BEFORE Transfer of Assets/Costs | 2.8% | | | | | |
| | | -0.1% | AFTER Transfer of Assets/Costs | 1.7% | 1.8% | 2.2% | 2.5% | 2.6% | 2.8% |
| | | | Net Income/ Total Equity - % | | | | | | |
| | | 21.7% | BEFORE Transfer of Assets/Costs | 7.1% | | | | | |
| | | -23.6% | AFTER Transfer of Assets/Costs | 8.2% | 3.1% | 1.7% | 1.2% | 1.6% | 1.9% |
| | | | **CASH FLOW RATIOS:** | | | | | | |
| | | | Debt Service Ratio | | | | | | |
| | | 8.10 | BEFORE Transfer of Assets/Costs | 10.73 | 10.96 | 3.13 | 2.28 | 2.60 | 2.76 |
| | | | Self-Financing Ratio | | | | | | |
| | | 64.4% | BEFORE Transfer of Assets/Costs | 96.0% | 26.4% | 11.8% | 9.5% | 16.8% | 87.0% |
| | | | **BALANCE SHEET RATIOS:** | | | | | | |
| | | 1.78 | Current Ratio | 1.86 | 2.12 | 3.02 | 3.46 | 3.60 | 4.32 |
| | | 0.01 | Cash at Bank to Sales - months | 0.01 | 0.10 | 0.50 | 0.67 | 0.68 | 0.97 |
| | | 0.93 | Accts.Receivable to Sales - months | 0.92 | 0.92 | 0.92 | 0.92 | 0.92 | 0.92 |
| | | | Debt to Equity Ratio - % | | | | | | |
| | | 26.0% | BEFORE Transfer of Assets/Costs | 11.2% | | | | | |
| | | | AFTER Transfer of Assets/Costs | | 10.5% | 24.8% | 34.8% | 38.9% | 34.2% |

Billions Zloty at Base Year Prices

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# Exhibit 11-17
## CASE 3
## OPERATING AND FINANCIAL RATIOS – DISTRIBUTION COMPANIES

| PRO-FORMA 1989 | ACTUAL 1990 | ACTUAL 1991 | POLISH DISTRIBUTION COMPANIES Year End -- December 31 | ESTIMATE 1992 | FORECAST 1993 | 1994 | 1995 | 1996 | 1997 |
|---|---|---|---|---|---|---|---|---|---|
| | | | **SALES RATIOS** | | | | | | |
| 19.942 | 213.444 | 353.994 | Average Sales Tariff -- Zl/ Kwh | 542.100 | 542.100 | 623.415 | 716.927 | 814.000 | 814.000 |
| | 135.258 | 221.677 | Average Purchase Cost -- Zl/ Kwh | 339.071 | 336.295 | 377.161 | 410.071 | 515.734 | 564.605 |
| | -7.7% | -6.0% | Annual Sales Growth (Kwh) -- % | -1.4% | 2.6% | 2.9% | 4.0% | 2.6% | 2.7% |
| | 687.8% | 55.9% | Annual Sales Growth (Zl) -- % | 51.1% | 2.6% | 16.4% | 19.6% | 16.5% | 2.7% |
| | | | **OPERATING RATIOS** | | | | | | |
| | 8.3% | 11.6% | Distribution Losses - % | 10.6% | 9.9% | 9.2% | 8.4% | 8.5% | 8.5% |
| | 63.4% | 62.6% | Energy Purchase/ Sales -- % | 62.5% | 62.0% | 60.5% | 57.2% | 63.4% | 69.4% |
| 5.4% | 10.4% | 8.4% | Operating Income/ Sales -- % | 14.3% | 12.5% | 14.6% | 19.2% | 12.6% | 3.8% |
| | 3.4% | 3.9% | Operating Income/ Net Assets -- % | 20.0% | 15.0% | 15.1% | 18.0% | 10.8% | 2.8% |
| | 2.9% | 3.4% | Net Income after Tax/ Equity -- % | 7.5% | 7.2% | 6.6% | 8.0% | 5.2% | 1.8% |
| | | | **FINANCIAL RATIOS** | | | | | | |
| | 1.3 | 0.8 | Current Ratio | 4.0 | 61.1 | 78.8 | 74.3 | 86.4 | 80.2 |
| | 7.2% | 22.6% | Total Debt/ Equity -- % | 11.1% | 2.5% | 1.8% | 1.4% | 1.1% | 1.0% |
| | | | Self-Financing Ratio -- % | | 162.6% | 113.3% | 124.5% | 114.0% | 103.0% |

Billions Zloty at Base Year Prices

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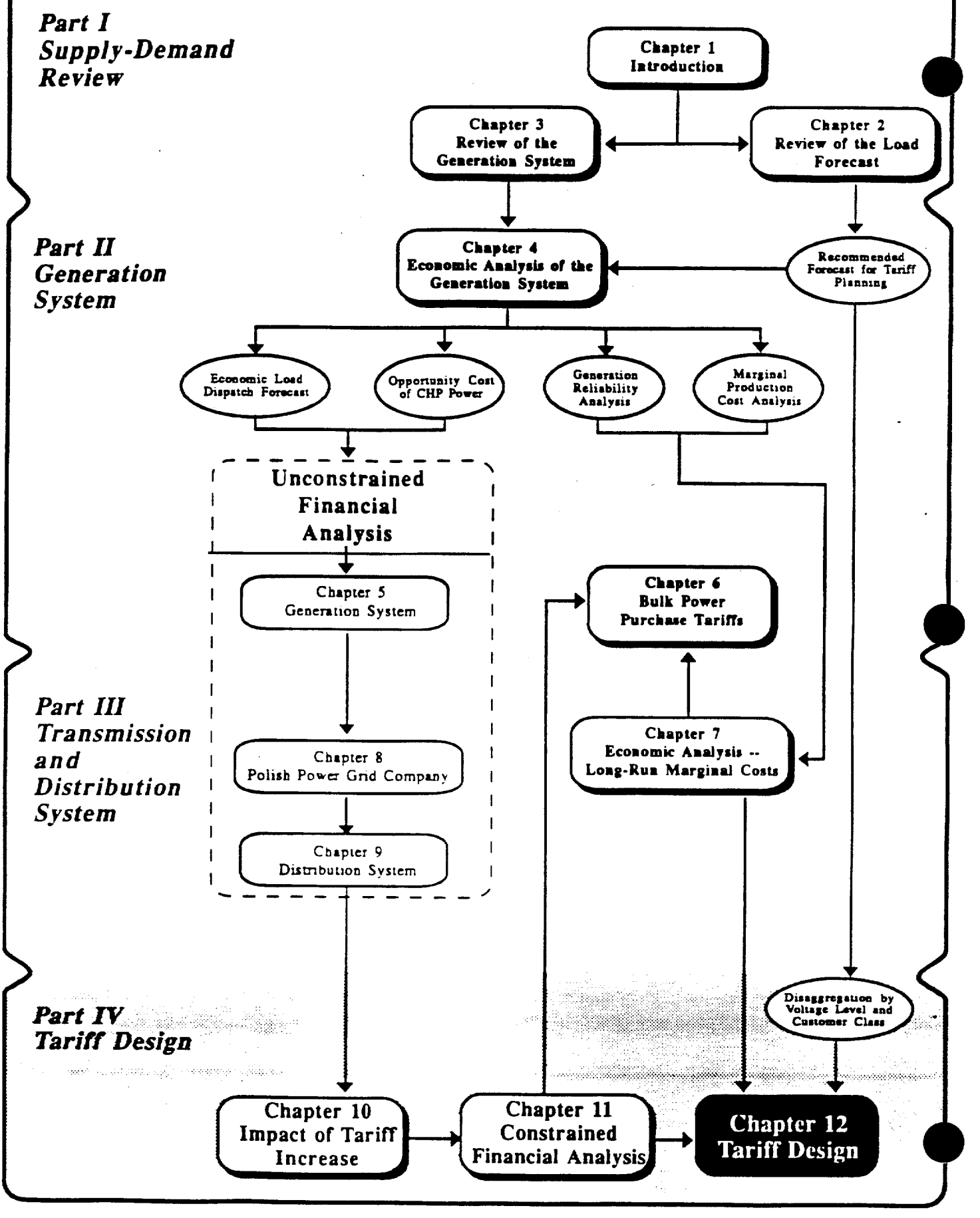
30 Jun 93

# Road Map to the Study



# CHAPTER 12: TARIFF DESIGN

This chapter develops our recommendations for tariff restructuring. Section 12.1 presents a review and evaluation of existing tariffs in light of information on the long-run marginal cost (LRMC) structure and financial revenue requirements as determined in Chapters 7 through 9, respectively.

The tariff restructuring begins with a determination of individual tariff class revenue responsibilities in Section 12.2. This is followed by a presentation of the tariff structures for bulk electricity sales by PPGC to the distribution companies. Section 12.3 presents the uniform bulk sales tariff and Section 12.4 outlines illustrative bulk sales tariffs for tariffs differentiated for individual distribution companies. Section 12.5 presents "final sales" (retail) tariffs that recover class-specific revenue responsibility. Section 12.6 discusses optional tariffs recommended to PPGC and the distribution companies. Finally, Section 12.7 outlines other tariff clauses/provisions.

Throughout this chapter, we compare "current" tariff yields (i.e., based on price list No. 7-Z/92) with financial and economic costs of supply expressed in mid-1992 prices. To facilitate this comparison, the current yields are also restated at the levels of mid-1992.

## 12.1 REVIEW OF EXISTING TARIFF STRUCTURE AND LEVELS

All of PPGC's domestic bulk sales are to 33 independent distribution companies (DCs), which in turn resell electricity to final consumers. Tariffs to each company are adjusted to permit uniform national tariffs to these end-users. PPGC's average yield on bulk sales was 334.6 Zl/kWh in October 1992, and is estimated to be 381.4 Zl/kWh as of February 1993 (339.8 Zl/kWh at mid-1992 prices).

Exhibit 12-1 summarizes the retail tariff structure that came into effect on January 1, 1993 (No. 7-Z/92). The tariffs are based strictly on consumer service voltage, with time-of-day rate options offered for each class. Based on billed sales data for the first half of 1992, tariff "A" (High Voltage, 60 to 220 kV) represents approximately 31 percent of total sales. Tariff "B" (Medium Voltage, 1 to 60 kV) customers account for about 26 percent of total sales. All of these customers pay both demand and energy charges.

Tariff "C" (Low Voltage, below 1 kV) is divided into two classes. The first is customers with maximum demand above 40 kW or consumption over 80 MWh/year (tariff "C2"), which account for about 3 percent of total sales. The second is non-residential customers consuming

EXHIBIT 12-1

**MAPPING OF CURRENT (No. 7 – Z/92) AND PREVIOUS (No. 7 – Z/91) TARIFF CLASSES**

| CURRENT RETAIL TARIFF (No. 7–Z/92) | | | equivalent to –> | PREVIOUS RETAIL TARIFF (No. 7–Z/92) | | |
|---|---|---|---|---|---|---|
| Tariff | Customer Segment | % of Sales 1/ | | Tariff | Customer Segment | % of Sales 1/ |
| A21 | HV – All non–residential (demand, flat energy) | 0.1% | | A9 (3%) | HV Rail Transport | 0.1% |
| A22 | HV – All non–residential (demand, energy – 2 TOD) | 1% | | A2 | HV Industry | 1% |
| A23 | HV – All non–residential (demand, energy – 3 TOD) | 29% | | A3 | HV Industry | 29% |
| B21 | MV – All non–residential (demand, flat energy) | 9% | | A11 | MV Industry | 3% |
| | | | | A9 (97%) | MV Rail Transport | 5% |
| | | | | E11 | MV Commercial | 1% |
| | | | | F11 | MV Large Farms | 0.5% |
| B22 | MV – All non–residential (demand, energy – 2 TOD) | 10% | | A21 | MV Industry | 9% |
| | | | | E21 | MV Commercial | 0.3% |
| | | | | F21 | MV Large Farms | 0.2% |
| B23 | MV – All non–residential (demand, energy – 3 TOD) | 7% | | A31 | MV Industry | 7% |
| C21 | LV – All non–residential (demand, flat energy) | 2% | | B1 | LV Industry | 2% |
| C22a,b | LV – All non–residential (demand, energy – 2 TOD) | 1% | | B2 | LV Industry | 1% |
| C11 | LV – All non–residential (flat energy only) | 10% | | D | Street Lights | 2% |
| | | | | E1 | LV Commercial | 9% |
| C12a,b | LV – All non–residential (energy only – 2 TOD) | 1% | | E2 | LV Commercial | 1% |
| G11 | LV – Residential/Small Farm (flat energy only) | 23% | | F1 | Small Farms | 5% |
| | | | | G1 | Residential | 18% |
| G12 | LV – Residential/Small Farm (energy only – 2 TOD) | 6% | | F2 | Small Farms | 3% |
| | | | | G2 | Residential | 3% |

1/ Based on sales data for the first half of 1992.

less than 40 kW or 80 MWh/year (tariff "C1"), which comprise approximately 11 percent of total sales. Only the former group is assessed a demand charge.

Residential and small farm customers (tariff "G") account for the remaining 29 percent of system retail sales.

Although the current tariff classes do not follow traditional customer classifications (industrial, commercial, residential, street lights, etc.), we know the composition of the current classes from the tariff structure that was in effect throughout 1992 (No. 7-Z/91). For comparison, these tariff groups are also shown in Exhibit 12-1. The current HV sales (tariff "A") are almost exclusively to industry, with a very small rail transport component. The MV sales (tariff "B") are also dominated by industry (19 percent of total sales), with lesser shares attributable to rail transport (5 percent), commerce (1 percent) and large farms (1 percent). LV sales above 40 kW (or 80 MWh/year) all also all industrial, accounting for 3 percent of final sales. LV sales below 40 kW are commercial (10 percent) and street lights (about 2 percent). Finally, LV residential sales (tariff "G") are predominantly to households (21 percent of total sales), with a significant small farm component (8 percent of total sales).

The data reveal the dominance of industry in the Polish economy. Approximately 52 percent of total final sales go to the industrial sector. Surprisingly, only 17 percent of all final sales are consumed by rail transport, commerce, and large agricultural consumers combined.

Exhibits 12-2 and 12-3 present the essential features of the retail electricity tariffs in effect today (No. 7-Z/92) and during the last quarter of 1992 (No. 7-Z/91).

### 12.1.1 Overall Assessment of Tariff Levels

From a resource allocation and purely economic efficiency point of view, tariffs should be set at parity to the economic cost of supply. In practice, other considerations must also be balanced. This means that any restructuring of tariffs should strive to bring tariffs at each voltage level in closer alignment with the true cost of supply. Therefore, as a starting point, it is useful to examine the efficiency implications of existing tariff levels vis-a-vis the marginal cost, as defined earlier in Chapter 7 and reproduced here in Exhibit 12-4.

At the PPGC level, the data highlight the fact that the estimated current yield (i.e., as of the February 1993 tariff increase) is 381.4 Zl/kWh (339.8 Zl/kWh at mid-1992 prices). By comparison, the economic cost of supply is 708.5 Zl/kWh (mid-1992 prices) and the 1994 financial revenue requirement (also at mid-1992 prices) has been estimated in Chapter 8 to be

EXHIBIT 12-2

**Retail Tariffs Effective 10/1/1992 (No. 7 – Z/91)**

| Tariff Class | Service Voltage | Customer Segments | DEMAND CHARGE (ZI/KW/Month) Contract | Measured | Excess | ENERGY CHARGE (ZI/KWh) Flat | Peak | Off-Peak | Day | Night |
|---|---|---|---|---|---|---|---|---|---|---|
| A11 | MV | Industry | 15.970 | 30.030 | 159.700 | 440 | – | – | – | – |
| A2 | HV/MV | Industry | 15.810 | 28.470 | 158.100 | – | 670 | 230 | – | – |
| A21 | HV/MV | Industry | 15.970 | 30.030 | 159.700 | – | 620 | 210 | – | – |
| A3 | HV/MV | Industry | 15.810 | 28.470 | 158.100 | – | 490 | – | 300 | 170 |
| A31 | HV/MV | Industry | 15.970 | 30.030 | 159.700 | – | 490 | – | 270 | 150 |
| A9 | HV/MV | Transport | 15.970 | 30.030 | 159.700 | 240 | – | – | – | – |
| | HV/MV | Transport | 15.970 | – | 159.700 | 330 | – | – | – | – |
| B1 | LV | Industry | 17.390 | 39.530 | 173.900 | 470 | – | – | – | – |
| B2 | LV | Industry | 17.390 | 39.530 | 173.900 | – | 940 | 290 | – | – |
| D | LV | Street Lights | – | – | – | 1180 | – | – | – | – |
| | LV | Street Lights | – | – | – | 830 | – | – | – | – |
| E1 | LV | Commercial | – | – | – | 830 | – | – | – | – |
| | LV | Commercial | – | – | – | 770 | – | – | – | – |
| E2 | LV | Commercial | – | – | – | – | 1140 | 410 | – | – |
| E11 | HV/MV | Commercial | 17.390 | 39.530 | 173.900 | 400 | – | – | – | – |
| E21 | HV/MV | Commercial | 17.390 | 39.530 | 173.900 | – | 650 | 210 | – | – |
| F11 | LV | Farms | 13.279 | 27.100 | 132.800 | 400 | – | – | – | – |
| F21 | LV | Farms | 13.279 | 27.100 | 132.800 | – | 480 | 210 | – | – |
| R | | Temporary | – | – | – | 1130 | – | – | – | – |
| F1, G1 | LV | Residential/Sm Farms | – | – | – | 700 | – | – | – | – |
| F2, G2 | LV | Residential/Sm Farms | – | – | – | – | – | – | 810 | 320 |

EXHIBIT 12-3

**Retail Tariffs Effective 1/1993 (No. 7 – Z/92)**

| Tariff Class | Service Voltage | Customer Segments | DEMAND CHARGE (Zl/KW/Month) Contract | Measured | Excess | ENERGY CHARGE (Zl/KWh) Flat | Peak | Off-Peak | Day | Night |
|---|---|---|---|---|---|---|---|---|---|---|
| A21 | HV | All Non-Residential | 10.000 | 29.000 | 50.000 | 410 | – | – | – | – |
| A22 | HV | All Non-Residential | 10.000 | 29.000 | 50.000 | – | 655 | 350 | – | – |
| A23 | HV | All Non-Residential | 10.000 | 29.000 | 50.000 | – | 655 | – | 355 | 180 |
| B11 | MV | All Non-Residential | – | – | – | 650 | – | – | – | – |
| B21 | MV | All Non-Residential | 11.000 | 30.000 | 55.000 | 415 | – | – | – | – |
| B22 | MV | All Non-Residential | 11.000 | 30.000 | 55.000 | – | 705 | 350 | – | – |
| B23 | MV | All Non-Residential | 11.000 | 30.000 | 55.000 | – | 705 | – | 385 | 200 |
| C21 | LV>40kW | All Non-Residential | 12.100 | 40.000 | 60.500 | 640 | – | – | – | – |
| C22a | LV>40kW | All Non-Residential | 12.100 | 40.000 | 60.500 | – | 960 | 520 | – | – |
| C22b | LV>40kW | All Non-Residential | 12.100 | 40.000 | 60.500 | – | – | – | 650 | 360 |
| C11 | LV<40kW | All Non-Residential | – | – | – | 930 | – | – | – | – |
| C12a | LV<40kW | All Non-Residential | – | – | – | – | 1150 | 530 | – | – |
| C12b | LV<40kW | All Non-Residential | – | – | – | – | – | – | 1040 | 400 |
| R | | Temporary Service | – | – | – | 1230 | – | – | – | – |
| G11 | LV | Residential/Sm Farms | – | – | – | 785 | – | – | – | – |
| G12 | LV | Residential/Sm Farms | – | – | – | – | – | – | 925 | 340 |

# EXHIBIT 12-4

## STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS - BULK

| TARIFF CLASS | SERVICE VOLTAGE | COINCI-DENCE | LOAD FACTOR | ENERGY SHARES PEAK | ENERGY SHARES MID-PEAK | TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW | ENERGY tysZl/KWh | TOTAL tysZl/KWh | DEMAND CHARGE SHARE | H1/1992 SALES GWh | CURRENT YIELD tysZl/KWh |
|---|---|---|---|---|---|---|---|---|---|---|---|
| DISTRIBUTION COS. | HV | 1.00 | 0.65 | 0.20 | 0.28 | 121.10 | 0.4533 | 0.7085 | 36% | 50434 | 0.3398 |
| BULK SYSTEM AVERAGE | | | | 0.20 | 0.28 | 121.10 | 0.4533 | 0.7085 | | 50434 | 0.3398 |
| Equivalent tysZl/KWh | | | | | | 0.2552 | 0.4533 | 0.7085 | | | |
| % of System Average | | | | | | 36% | 64% | 100% | | | |

## STRICT LONG RUN MARGINAL COST BASED TARIFF BY TARIFF CLASS - RETAIL

| TARIFF CLASS | SERVICE VOLTAGE | COINCI-DENCE | LOAD FACTOR | ENERGY SHARES PEAK | ENERGY SHARES MID-PEAK | TOTAL MARGINAL COST/MONTH CAPACITY tysZl/KW | ENERGY tysZl/KWh | TOTAL tysZl/KWh | DEMAND CHARGE SHARE | H1/1992 SALES GWh | CURRENT YIELD tysZl/KWh |
|---|---|---|---|---|---|---|---|---|---|---|---|
| INDUSTRIAL | HV | 0.81 | 0.60 | 0.16 | 0.27 | 98.09 | 0.4354 | 0.6594 | 34% | 14090 | 0.3874 |
| | MV | 0.63 | 0.42 | 0.18 | 0.31 | 117.62 | 0.4652 | 0.8488 | 45% | 8884 | 0.4995 |
| | LV | 0.54 | 0.31 | 0.18 | 0.31 | 154.27 | 0.5203 | 1.2020 | 57% | 1334 | 0.7828 |
| TRACTION | HV | 0.93 | 0.48 | 0.19 | 0.30 | 112.62 | 0.4534 | 0.7748 | 41% | 67 | 0.4606 |
| | MV | 0.93 | 0.48 | 0.19 | 0.30 | 173.63 | 0.4671 | 0.9627 | 51% | 2178 | 0.4715 |
| COMMERCIAL | MV | 0.63 | 0.49 | 0.20 | 0.32 | 117.62 | 0.4755 | 0.8044 | 41% | 641 | 0.4934 |
| | LV | 0.55 | 0.30 | 0.20 | 0.32 | 157.13 | 0.5323 | 1.2498 | 57% | 4464 | 0.7745 |
| AGRICULTURAL | MV | 0.54 | 0.38 | 0.20 | 0.32 | 100.82 | 0.4755 | 0.8390 | 43% | 320 | 0.5287 |
| RETAIL | LV | 0.49 | 0.25 | 0.27 | 0.25 | 139.99 | 0.5479 | 1.3150 | 58% | 13616 | 0.6310 |
| ST. LIGHTING | LV | 1.00 | 0.50 | 0.21 | 0.04 | 285.69 | 0.4659 | 1.2486 | 63% | 742 | 0.7884 |
| DISTRIBUTION COMPANY AVERAGE | | | | 0.20 | 0.28 | 128.31 | 0.4888 | 0.9879 | | 46336 | 0.5421 |
| Equivalent tysZl/KWh | | | | | | 0.4991 | 0.4888 | 0.9879 | | | |
| % of System Average | | | | | | 51% | 49% | 100% | | | |

367.0 Zl/kWh. At the retail (final sales) level, the estimated current yield (as January 1993) is 621.9 Zl/kWh (542.1 Zl/kWh at mid-1992 prices), the strict economic cost of supply is 987.9 Zl/kWh, and the financial revenue requirement in 1994 (mid-1992 prices) has been estimated to be 623.4 Zl/kWh. These data reveal a financial subsidy for all final sales on the order of Zl $7.5 \times 10^{12}$ per year, or equivalently, about US $0.6 billion per year at an exchange rate of 13,400 Zl/US$.

The economic subsidy -- measured as the difference between current yield and LRMC -- for all final sales is on the order of Zl $4.1 \times 10^{13}$ per year, or equivalently, about US $3.0 billion per year. The incidence of these subsidies is widespread, with the most extreme case of distortions to be found among low-voltage customers, in particular tariff class "G" (including residential and small farm users).

Generally speaking, it is not prudent economic policy or financial policy to price electricity --- or for that matter, any other good or service -- such that a very high percentage of customers and sales are subsidized substantially. Any subsidies received by one customer segment must be made up by charging more than otherwise necessary to another customer segment. This distorts the price signals to all customers. Those who are being subsidized will not make efficient consumption decisions because the price they pay is lower than the cost to the nation for providing the service. Additionally, efficiency losses occur because others must pay more. This distorts their consumption levels and patterns as well, and creates the potential for significant distortionary impacts economy-wide due to resource and capital mis-allocation.

### 12.1.2 Tariff "G" - Residential

The residential tariff includes domestic sales (formerly, tariffs "G1" and "G2") and small farms (formerly served under tariffs "F1" and "F2"). Larger farms (formerly, tariffs "F11" and "F21") are served under a separate low-voltage tariff discussed later. Tariff "G" also includes group accommodation facilities, such as dormitories, schools, etc.

The residential tariff structure is a flat energy charge for all kWh (tariff "G11"). As an option, a day/night time-of day (TOD) tariff ("G12") is available. The estimated average yield (as of January 1993) is 744.4 Zl/kWh (631.0 Zl/kWh at mid-1992 prices), as compared to an economic cost of supply of 1,315.0 Zl/kWh and a revenue-neutral LRMC of 828.9 Zl/kWh. At current sales levels, these numbers imply a financial subsidy of about Zl 5 trillion per year and an economic subsidy of about Zl 18 trillion per year. The tariff represents about 75 percent of the financial cost of supply and about 50 percent of the economic cost.

The TOD tariff option divides the day into high price hours (14 hours/day, to be specified by each distribution company) and low price hours (the remaining 10 hours/day, including two mid-day valley hours). The tariffs for these two rating periods are 925 and 340 Zl/kWh, respectively.

Single-block residential tariff structures as employed in Poland are truly laudatory. Far more common in other countries are increasing block tariffs designed to facilitate cross-subsidies between and among different customer groups. We have specifically not considered such options in the present study because of PPGC's (and the Polish Government's) stated objective to avoid any subsidies in the provision of electricity service.

Chapter 11 argues that electricity costs do not impose (on average) a disproportionate burden on the consuming public. Nevertheless, the concern has been expressed that electricity costs represent a higher share of low-income household budgets. One option for dealing with this concern is to design a multi-block tariff which, in effect, provides a cross-subsidy from rich to poorer residential consumers. While this option is not being recommended at this time, it is discussed briefly in the following analysis of residential bill frequency.

### 12.1.3 Bill Frequency Analysis of the Residential Tariff

The bill frequency analysis (BFA) utilizes historical customer billing records to develop two summary characteristics.[1] The BFA provides estimates of the distribution of bills by consumption level, e.g., the fraction of all bills rendered that had a billed consumption level of 50 kWh or less per month. The BFA also estimates the distribution of sales, e.g., the fraction of all sales accounted for up to the 50 kWh per month consumption block. This analysis provides useful insights for tariff block sizing and in simulating future revenues from new tariff structures.

The BFA uses a concept called the "consolidated factor." This factor distinguishes between the two components of sales at any particular interval, and is estimated as the sum of all kilowatt-hours in bills rendered from zero consumption up to that interval but only up to that interval. Consider, for example, the sales in kilowatt-hours at 100 kWh per month. A portion of the sales at 100 kWh is made up of the sum of all kilowatt-hours in bills rendered under that

[1] We have not prepared a separate BFA for this study. Rather, we have relied on a study regularly prepared by the Polish Energy Information Center.

amount. The second portion of the consolidated factor is 100 kWh in every bill rendered in excess of the 100 kWh.

The profiles of bills rendered and sales of electrical energy to all residential customers are shown in Exhibit 12-5. The data aggregate sales and bills for tariff 7-Z/91 classifications "G1," "G2," "F1," and "F2."

**Exhibit 12-5**
**Residential Bill Frequency: Tariff Classes G1, G2, F1, F2**

| Sales Interval (kWh/month) | Cumulative Percent of Bills | Cumulative Percent of Sales (kWh) |
|---|---|---|
| 0 | 0.00% | 0.00% |
| 83 | 36.18% | 10.77% |
| 167 | 69.90% | 34.49% |
| 250 | 83.46% | 50.08% |
| 333 | 89.25% | 59.57% |
| 417 | 92.60% | 66.63% |
| 667 | 97.12% | 79.80% |
| 833 | 98.28% | 84.61% |
| 1,667 | 99.69% | 93.19% |
| 2,500 | 99.88% | 95.21% |
| 4,167 | 99.95% | 96.58% |
| 8,333 | 99.99% | 97.57% |
| 83,333 | 100.00% | 100.00% |

Note: Zero bills not estimated.

The median points of bills rendered to customers (the point at which 50 percent of the bills are rendered over and 50 under) is approximately 115 kWh per month. The median point of sales in kilowatt-hours per month is about 250 kWh per month. The significance of the chart can be further understood by reviewing the characteristics of sales to residential customers at several intervals.

The billing data indicate that there are about 10,000 bills rendered over 2,500 kWh per month. This is a high number, even after considering that group accommodation facilities are included within this tariff. We suggest that an exception report should be prepared identifying these very large accounts to ensure that they are not misclassified commercial accounts.

Under the present tariff structure, the price of electricity in the residential tariff is much lower than in tariff "C1" (LV < 40 kW). Thus, it is more advantageous for low-voltage commercial customers to be classified as residential. While we do not know the extent (if any) of such misclassification, it is a common problem in other countries. Ultimately, any incentive for strategic misclassification on the part of a large customer can be eliminated by making the price for non-residential customers less than or equal to that of the residential customers. The economic cost structure supports this realignment of tariff levels.

As noted above, it would be possible to "soften" the shock of required residential tariff increases by developing a three-block tariff. The first, subsidized block, would include only electricity consumption associated with basic needs. To illustrate, this block might be set at 83 kWh/month (1,000 kWh/year). The BFA indicates that approximately 36 percent of all bills are rendered at or below this level, and that approximately 11 percent of all sales are billed at this level (including customers that consume more than 83 kWh/month). A second block, including the largest share of sales and bills, would be billed at the revenue-neutral LRMC. Finally, a tail block of high-consumption customers (e.g., over 667 kWh/month, or 8,000 kWh/year, representing only about 1.6 percent of all bills, but nearly 15 percent of all sales) would be charged strict LRMC, cross-subsidizing the low-income consumers. Of course, the structuring of such an option would require more detailed revenue analysis, but in our opinion, the option is far better than a more broadly based residential subsidy.

The argument for this tariff structure is, of course, that high subsidy levels place an unfair burden on other consuming sectors of the economy. Electricity is an expensive good in that it requires substantial commitments of the nation's productive resources. Thus, subsidies, if necessary, should be confined solely to the poorest of the poor.

The disadvantage of a three-block tariff is that, once established, utilities in other countries have found it very hard to eliminate. Thus, we would only consider this option if the burden

imposed by an "unblocked" structure is considered "unfair" or politically unacceptable. Based on the analysis in Chapter 11, we do not recommend a blocked residential tariff.

The policy of providing free electricity to employees at all levels of the power system (the so-called "Energy Worker's" tariff) is inconsistent with the goal of economic efficiency pricing. This practice should be eliminated. The subsidy is significant in financial as well as economic terms; the average current yield (based on today's tariffs (7-Z/92) applied to sales data for the first half of 1992) for the residential class is 744.4 Zl/kWh without the subsidy and 723.2 Zl/kWh when the energy workers' consumption is included, nearly a 3 percent decrease.

Of course, the subsidy cannot simply be eliminated, since "free" electricity is a component of current income for these workers. Rather, a special wage/salary increase should be provided to every worker based on an equitable estimate of the "market value" of this subsidy. Then, the subsidy should be eliminated. Workers will then have the option of continuing to consume energy at their present rate (i.e., no change in current electricity consumption or net income), or they may choose to reduce consumption and apply the increased income to other needs.

### 12.1.4 Tariff "A" - High Voltage

This new class includes all high-voltage customers, formerly served under HV industrial classes "A2" and "A3." It also includes a very small portion of traction consumption (3 percent of former class "A9"). The class accounts for approximately 30 percent of total sales. The structure of current tariffs parallels that of classes "B" and "C2" discussed above (see Exhibit 12-1).

The current yield (January 1993) from this tariff is estimated to be 457.4 Zl/kWh, (387.7 Zl/kWh at mid-1992 prices) as compared to the economic cost of 659.9 Zl/kWh and a revenue-neutral LRMC of 416.4 Zl/kWh.

Customers pay both a demand charge and energy charge. The basic demand charge has three components -- a contract charge, a measured demand charge, and a penalty of five times the contract rate if measured demand exceeds the contracted demand level. Effective January 1993, the demand charges are 10,000 Zl/kW/month for contract demand and 29,000 Zl/kW/month for measured demand. The basic tariff offers a flat energy charge, currently 640 Zl/kWh. As with other non-residential tariff classes, two optional and three time-of-day energy structures are offered (peak/off-peak, and peak/off-peak(day)/off-peak(night). These tariffs are summarized in Exhibit 12-3.

### 12.1.5 Tariff "B" - Medium Voltage

This new class includes all medium-voltage customers, formerly served under separate MV classes for industry ("A11," "A21," "A31"), traction (97 percent of "A9"), commercial ("E11," "E21," "F11," "F21"). The class accounts for approximately 26 percent of total sales.

In terms of structure, tariff "B" rates largely parallel the class "A" tariffs described above. They incorporate slightly higher demand charges and energy charges. Optional TOD rates are offered. The actual tariffs are summarized in Exhibit 12-1. The current yield (January 1993) from this tariff is estimated to be 583.8 Zl/kWh (494.9 Zl/kWh at mid-1992 prices), as compared to the economic cost of 866.8 Zl/kWh and a revenue-neutral LRMC of 547.0 Zl/kWh.

### 12.1.6 Tariff "C2" - Low Voltage > 40 kW

This class includes all non-residential low-voltage customers with maximum demand greater than 40 kW and annual consumption above 80 MWh. This new tariff class is composed predominantly of smaller-sized industrial customers formerly served under tariffs "B1" and "B2."

In terms of structure, tariff "C2" rates parallel the class "A" tariffs described above, albeit at higher rate levels. The basic demand charge (effective January 1993) is 12,100 Zl/kW/month for contract demand and 30,000 Zl/kW/month for measured demand. The basic tariff offers a flat energy charge, currently 640 Zl/kWh. As with tariff "C1," two optional TOD structures are also available for the energy charge (see Exhibit 12-1).

The current yield (January 1993) from this tariff is estimated to be 923.5 Zl/kWh (782.8 Zl/kWh at mid-1992 prices), as compared to the economic cost of 1,202.0 Zl/kWh and a revenue-neutral LRMC of 758.5 Zl/kWh. At current sales levels, these numbers imply no financial subsidy, but they suggest an economic subsidy on the ordr of Zl 1,100 billion per year.

The economic and financial costs of supply are high due to a very low observed load factor among these smaller industries. For example, the load factor for October 1992 was 0.30, and for all of 1991 it was only 0.29. For a customer on this rate with a monthly load factor of 0.30, the demand charge currently represents about 30 percent of his average monthly bill. By contrast, the economic cost structure indicates that this share should be over 60 percent.

It is sometimes suggested that preferential treatment to industrial customers may be justified in order to stimulate industrial growth. Government interventions of this nature -- even though they may be well intentioned and welcome as far as the beneficiaries are concerned -- ultimately distort the tariff for all customers and lead, on net, to more efficiency losses than can be offset by any gains to the recipients of the subsidy.

### 12.1.7 Tariff "C1" - Low Voltage < 40 kW

This class includes all non-residential low-voltage customers with maximum demand of less than 40 kW and annual consumption below 80 MWh. As noted in Exhibit 12-1, this new tariff class is composed predominantly of small to medium-sized commercial customers formerly served under tariffs "E1" and "E2." It also includes street lighting (formerly tariff "D").

The basic tariff is a flat energy charge, currently 930 Zl/kWh. Two optional structures are also available, charging either different peak/off-peak or day/night rates.

The current yield (January 1993) from this tariff is estimated to be 913.6 Zl/kWh (774.5 Zl/kWh at mid-1992 prices), as compared to the economic cost of 1,249.8 Zl/kWh and a revenue-neutral LRMC of 788.6 Zl/kWh. At current sales levels, these numbers imply only a modest financial subsidy, but they indicate an economic subsidy of Zl 4.2 trillion per year.

## 12.2 REVENUE RESPONSIBILITY BY TARIFF CLASS

The financial analysis in Chapters 8 and 9 (and subsequent sensitivity analyses) specify the average revenue requirements for PPGC, the distribution companies, and for all final system sales. These requirements for 1994 and the corresponding implications for percentage increases that could be required are summarized in the following table.

| | 1994 Financial Revenue Requirement | | |
|---|---|---|---|
| | 1994 Target Yield (mid-92 Zl/kWh)* | Est. Current Yield (mid-92 Zl/kWh) | Increase Required (%) |
| PPGC | 376.0 | 339.8 | 11% |
| DCs | 623.4 | 542.1 | 15% |

* based on the most likely "constrained" financial scenario developed in Chapter 12.

The class revenue responsibility analysis as well as the subsequent tariff design described in the remainder of this chapter are carried out in real terms (at mid-1992 prices). Although tariffs are being designed for 1994, uncertainty regarding domestic inflation and the Zloty:US$ exchange rate make it appropriate to conduct the analysis in constant prices.

The above data show that on a total final sales basis, the financial revenue requirement of 623.4 Zl/kWh for 1994 implies an average ***real*** tariff increase of approximately 15 percent. The procedure employed for tariff design is to allocate this revenue requirement to each tariff class, thereby defining the revenue responsibility for each class, and then to design specific tariffs for each class to match the revenue responsibility.

Exhibit 12-6 summarizes revenue responsibility by tariff class -- bulk and final sales -- based strictly upon the relative LRMC structure. The table shows current yield, strict LRMC, and revenue neutral LRMC, and finally, revenue responsibility for each tariff class. The "revenue neutral" LRMC is simply the strict LRMC scaled (on a class sales-weighted basis) to exactly collect the financial revenue requirement.

For PPGC sales, the revenue-neutral LRMC implies, for example, that the average price (yield) from PPGC sales to all distribution companies must be increased from 339.8 Zl/kWh (mid-1992 prices) to 376.0 Zl/kWh, an 11 percent increase. At the retail level, the revenue-neutral LRMC implies a ***real*** average price (yield) increase of 31 percent for residential customers (from 631.0 Zl/kWh today to 829.8 Zl/kWh), and considerably smaller increases for all other tariff classes. On a total final sales basis, the average increase required is about 15 percent.

The class revenue responsibilities in Exhibit 12-6 (the last two columns) are designed to incorporate adjustments to the class revenue-neutral LRMCs, if necessary. Possible

# EXHIBIT 12-6

## REVENUE RESPONSIBILITY BY CUSTOMER/TARIFF CLASS – BULK

| | |
|---|---|
| BILLING YEAR | 1994 |
| TOTAL GRID SALES (GWh) | 109072 |
| REVENUE REQUIREMENT | |
| TOTAL (tysZl MILLION) | 41011 |
| AVERAGE (tysZl/KWh) 1/ | 0.3760 |

| CUSTOMER/ TARIFF CLASS | H1/1992 SALES GWh | CURRENT YIELD2/ tysZl/KWh | STRICT LRMC3/ tysZl/KWh | REVENUE NEUTRAL STRICT LRMC tysZl/KWh | % CHNG | REVENUE RESPONSIBILITY tysZl/KWh | % CHNG |
|---|---|---|---|---|---|---|---|
| DISTRIBUTION COS. | 50434 | 0.3398 | 0.7085 | 0.3760 | 11% | 0.3760 | 11% |
| TOTAL BULK | 50434 | 0.3398 | 0.7085 | 0.3760 | 11% | 0.3760 | 11% |

1/ Approximate revenue target for 1994.
2/ Estimated average current yield after tariff increase of Q1/1993, in mid – 1992 prices.
3/ Escalated to 1994 prices, a 0.00% increase.

## REVENUE RESPONSIBILITY BY CUSTOMER/TARIFF CLASS – RETAIL

| | |
|---|---|
| BILLING YEAR | 1994 |
| TOTAL GRID SALES (GWh) | 100441 |
| REVENUE REQUIREMENT | |
| TOTAL (tysZl MILLION) | 62615 |
| AVERAGE (tysZl/KWh) 1/ | 0.6234 |

| CUSTOMER/ TARIFF CLASS | | H1/1992 SALES GWh | CURRENT YIELD2/ tysZl/KWh | STRICT LRMC3/ tysZl/KWh | REVENUE NEUTRAL STRICT LRMC tysZl/KWh | % CHNG | REVENUE RESPONSIBILITY tysZl/KWh | % CHNG |
|---|---|---|---|---|---|---|---|---|
| "A" | HV | 14157 | 0.3877 | 0.6599 | 0.4164 | 7% | 0.4164 | 7% |
| "B" | MV | 12023 | 0.4949 | 0.8668 | 0.5470 | 11% | 0.5470 | 11% |
| "C" (>40 kW) | LV | 1334 | 0.7828 | 1.2020 | 0.7585 | –3% | 0.7585 | –3% |
| "C" (<40 kW) | LV | 4464 | 0.7745 | 1.2498 | 0.7886 | 2% | 0.7886 | 2% |
| RETAIL | LV | 13616 | 0.6310 | 1.3150 | 0.8298 | 31% | 0.8298 | 31% |
| ST. LIGHTING | LV | 742 | 0.7884 | 1.2486 | 0.7879 | 0% | 0.7879 | 0% |
| TOTAL DC RETAIL | | 46336 | 0.5421 | 0.9879 | 0.6234 | 15% | 0.6234 | 15% |

1/ Approximate revenue target for 1994.
2/ Estimated average current yield after tariff increase of Q1/1993, in mid – 1992 prices.
3/ Escalated to 1994 prices, a 0.00% increase.

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adjustments might include, for example, 1) moderating to the extent possible a burdensome rate increase to the residential tariff, or 2) avoiding any bill increases that may be perceived as "unfair" in an intra-class comparison (e.g., no class should receive a tariff decrease when others are facing large increases).

In our analysis, we have concluded that the revenue-neutral LRMCs do not place an unfair burden on any particular class, and therefore no special adjustments have been made. The class revenue responsibilities shown in Exhibit 12-6 imply average yield adjustments ranging from a slight decrease for large commercial customers (tariff "C2") to the 31 percent increase for residential customers (tariff "G") noted above.

## 12.3 BULK/PPGC TARIFF DESIGN

This section develops the proposed tariff structures and levels for bulk sales-for-resale by PPGC to the distribution companies.

Revenue requirement targets for this analysis were developed as described in the financial analysis of Chapters 8 and 9, and the sensitivity analyses of Chapter 11. Economic efficiency considerations in developing the proposed tariff revision were based on: 1) estimates of LRMC obtained as described in Chapter 7, and 2) insights obtained from the analysis of existing tariffs as described in the preceding section.

At present, PPGC sells electricity to each distribution company based on a two-component energy tariff. Distributors are charged for (i) electrical energy ordered and (ii) electrical energy consumed. The former charge approximates a capacity charge (i.e., it is related to the fixed costs of producers providing capacity to supply ordered energy). The payment for ordered energy includes a penalty factor to encourage the "exactness" of the order, much like a penalty for exceeding contracted demand. The latter charge recovers the variable cost of energy actually consumed in the system; this charge is the same for all kWh sold to distributors. Optional settlement procedures based on coincident demand and TOD energy sales are also available for distributors that have the appropriate measuring equipment.

The sale price is set such that a company can recover its costs (including any permitted return) while re-selling electricity to final customers in its service territory at fixed national tariffs. The current (as of February 1993) average bulk tariff for all distribution company sales is 381.4 Zl/kWh (339.8 Zl/kWh at mid-1992 prices), as shown in Exhibit 12-6. As of 1994, PPGC plans to sell to all distribution companies on the basis of the two-component energy tariff or an optional coincident demand/TOD tariff, and permit end-user tariffs to be set by

each company subject to regulatory approval. Section 12.4 explores the implications of this change to three different types of distribution companies.

PPGC's objective should be to sell every kWh on a mandatory time-of-day (TOD) tariff. This tariff might include a separate demand charge, or the capacity costs may be incorporated into TOD energy tariffs. Due to the large number of delivery points, it will take some time to alter the current structure. Nevertheless, it should be possible to proceed in a phased manner to procure and install TOD meters at each delivery point within the next three years, i.e., by year-end 1996.

Section 12.5 describes the philosophy behind the recommended TOD tariff design with regard to retail tariffs; these assumptions are not repeated here. The following table presents a menu of acceptable options for bulk tariffs, based on the marginal cost structure and scaled to the current PPGC revenue requirement of 376 Zl/kWh (see Exhibit 12-6).

| PPGC Bulk Sales Tariff | | Demand (Z/kW/mo) | Energy (Zl/kWh) | | |
|---|---|---|---|---|---|
| Option | Season | | Peak | Mid-Peak | Off-Peak |
| Bulk-23 | Winter | 32.840 | 681 | 337 | 188 |
| | Summer | 29.870 | 503 | 441 | 199 |
| Bulk-22 | Winter | 32.840 | 446 | | 188 |
| | Summer | 29.870 | 438 | | 199 |
| Bulk-21 | Winter | 32.840 | 307 | | |
| | Summer | 29.870 | 313 | | |
| Bulk-13 | Winter | - | 842 | 498 | 188 |
| | Summer | - | 649 | 587 | 199 |
| Bulk-12 | Winter | - | 586 | | 188 |
| | Summer | - | 569 | | 199 |
| Bulk-11 | Winter | - | 376 | | |
| | Summer | - | 376 | | |

Note: Tariffs based on coincident demand.

The two-part tariff (i.e., both demand and energy charges) designs recover network capacity costs through demand, while generation capacity costs are incorporated in the energy rates.

(The rationale for this breakdown is discussed in Section 12.5.) The pure energy tariffs, of course, recover all capacity costs through TOD energy.

One problem with the tariff structures proposed is that they violate a basic tenet of marginal cost pricing, i.e., that the charge during any hour of the day should not fall below the strict marginal cost of off-peak energy. This result follows from the very low consolidated revenue requirement ("constrained" scenario 3) of PPGC in relation to the level of strict marginal costs. When strict marginal costs are allocated to appropriate rating periods and then scaled to the revenue requirement (376 Zl/kWh), off-peak energy charges fall below their desired minimum. On the other hand, if they are maintained at the value of off-peak energy, the differential between peak and off-peak energy diminishes significantly to prevent over-collection of revenue. On balance, we chose to preserve the appropriate peak/off-peak signals; the strict marginal energy cost is collected during both peak and mid-peak rating periods.

Having noted our strong preference for coincident demand metering or TOD rates which incorporate capacity costs, we recognize that metering constraints may delay the adoption of the proposed tariff structures. In the interim, it is proposed to maintain the present tariff design -- i.e., a pure energy tariff with its capacity (ordered energy) and energy components -- but adjust the levels upwards to ensure that designated revenue responsibilities are attained. Further, it would be unfair to impose TOD tariffs on distribution company purchases until the companies have the right to bill end-users on the same basis.

## 12.4 EFFECT OF UNIFORM BULK TARIFFS ON DISTRIBUTION COMPANIES

In order to evaluate the effect of uniform bulk sales tariffs on individual distribution companies and, in general terms, on retail tariffs, we studied three very different distribution companies. ZE Glivice serves a heavily industrialized area, with approximately two-thirds of final sales at high or medium voltage. ZE Warszawa covers a more balanced territory, with a mix of customer groups. Finally, ZE Bialystok serves a relatively rural area, with nearly half of all the company's customers in the residential tariff class (including small farms). These three companies currently account for about 13 percent, 5 percent, and 2.5 percent of all distribution company final sales, respectively. Relative sales by tariff class are shown in the following table:

| Tariff Class | Percent of Sales by Tariff Class * | | | |
|---|---|---|---|---|
| | All Distributors | ZE Glivice | ZE Warszawa | ZE Bialystok |
| "A" | 31% | 58% | 19% | 1% |
| "B" | 26% | 19% | 29% | 29% |
| "C2" > 40 kW | 3% | 2% | 4% | 4% |
| "C1" < 40 kW | 10% | 5% | 16% | 14% |
| Street Lights | 2% | 1% | - | 3% |
| "G" | 29% | 15% | 32% | 49% |
| TOTAL | 100% | 100% | 100% | 100% |

* Based on sales data for January through May, 1992

The national long run marginal cost structure (see Chapter 5) was applied to each company based on the above sales shares by tariff class and company-specific revenue requirements for 1994. Average strict LRMC and revenue neutral requirements vary widely among the three companies:

| | Retail Strict LRMC (Zl/kWh) | Revenue Requirement * (Zl/kWh) |
|---|---|---|
| ZE Glivice | 842 | 777 |
| ZE Warszawa | 1044 | 906 |
| ZE Bialystok | 1160 | 1245 |
| All Distributors | 988 | 785 |

* Based on "no increase in net borrowing" criterion. The revenue requirements are taken from the financial analysis of distribution companies presented in Chapter 9, i.e., the unconstrained financial analysis, which tends to magnify the dispersion of revenue requirements across companies.

On a tariff class basis, revenue-neutral strict LRMC's are reasonably close to the consolidated average for two of the three companies, as reported in the following summary:

| Tariff Class | Revenue-Neutral Strict LRMC by Tariff Class | | | |
|---|---|---|---|---|
| | All Distributors | ZE Glivice | ZE Warszawa | ZE Bialystok |
| "A" | 524 | 609 | 573 | 714 |
| "B" | 689 | 795 | 749 | 918 |
| "C2" > 40k | 955 | 1109 | 1043 | 1291 |
| W | 993 | 1153 | 1085 | 1342 |
| "C1" < 40k | 1045 | 1213 | 1141 | 1412 |
| W | 992 | 1152 | 1084 | 1341 |
| "G" St. Lights | 785 | 777 | 906 | 1245 |
| Average | | | | |

For ZE Glivice and ZE Warszawa, revenue-neutral LRMCs by class are within 10 to 15 percent of the consolidated average. The class LRMCs are much higher for ZE Bialystok, but this result is not surprising given this rural distributor's extremely high revenue requirement in comparison with the consolidated system. The data suggest that the effect of a uniform bulk tariff on final consumers will be relatively small in most cases.

Of course, these results could be revised (higher or lower) if detailed company-specific data were considered (e.g., more accurate distribution investment program, load research detailing class coincidence factors, load factors, and TOD energy shares. We do not believe, however, that these revisions would significantly alter our conclusion.

### 12.4.1 Implications Final Sales Tariff-Setting

Since it is planned that distribution companies purchase electricity based on uniform bulk tariffs by 1994, these companies may be faced with the need to develop their own end-use tariffs to recover company-specific revenue requirements. While the electricity sector wants to establish free and competitive markets, it also wants to encourage pricing based on

principles of economic efficiency. How will distribution companies be able to achieve both goals, given no experience and limited staff expertise regarding marginal cost pricing?

We propose that each distributor should be given two options for end-user tariff-setting:

1) Distributors will be permitted to adopt the national structure of marginal costs by class (defined in Section 12.5 and in Exhibits 12-4 and 12-6), appropriately adjusted by company-specific weights (i.e., sales by class) and scaled to the company's own financial revenue requirements. The preliminary analysis reported above suggests that end-user tariffs in different distribution companies would (in general) vary within an acceptable range if this method were applied. At the same time, required revenues would be collected based on a Poland-specific estimate of marginal cost structure. While a clear simplification, the argument for employing this approximation of class tariffs is that it is fast, low cost, and based (at the national level) or an accepted methodology.

2) If, however, the results of the foregoing calculation are not acceptable to a distributor, or the results derived differ from national average class tariffs by more than $\pm 20$ percent, the company should be required to prepare (or have prepared) its own marginal cost analysis as a basis for setting tariffs. Given the probable lack of expertise within the company, one option would be to train one or two Polish consulting teams (e.g., at Energoproject and/or the Institute of Power Engineering) to conduct these studies based on a standardized methodology. This approach would help to assure consistency of results among studies for different distributors.

## 12.5 FINAL SALES TARIFF DESIGN

This section discusses the proposed restructuring of tariffs for all sales made by distribution companies, given the individual class revenue responsibilities developed in Section 12.2. The discussion proposes many separate time-of-day (TOD) tariff options. The general philosophy employed in setting these rates is discussed first, followed by the specific tariff designs.

### 12.5.1 TOD Rate Design Philosophy

Specific seasonal and weekly rating periods identified for this study are:

Summer (May - October):

peak (7pm-10pm weekdays), mid-peak (7am-1pm weekdays), off-peak (all other hours)

Winter (November - April):

peak (4pm-9pm weekdays), mid-peak (7am-1pm weekdays), off-peak (all other hours)

Our basic approach for developing a TOD tariff is summarized in Exhibit 12-7. (For the purposes of this exhibit and the subsequent discussion, "peak hours" refers to both the peak and mid-peak periods of the week). This approach is appropriate for a power system such as that in Poland, where there is a relatively broad peak period and with relatively small seasonal variations in the cost structure.

### 12.5.2 Basis for Peak and Off-Peak Energy Charges

The strict marginal cost of energy in the peak and off-peak periods is obviously the basis for the energy charge. Other charges (capacity costs) may also be incorporated into the energy price, and these costs must be adjusted to reflect the class revenue responsibility. In no case, however, should a customer be charged less than the off-peak cost of energy, since it represents a minimum variable cost.

In addition, the portion of the marginal cost of generation capacity allocated by LOLP to the off-peak period must be spread across all kWh in that period.

Whether other capacity costs should be collected through a demand charge or TOD energy charges depends on whether 1) a coincident demand charge (i.e., one that is measured only in

## Exhibit 12-7
## Allocation of Marginal Cost Components for TOD Rate Design

| Marginal Cost Component | Demand Charge | Peak Energy Price | Off-Peak Energy Price |
|---|---|---|---|
| A. 2-part tariff (demand and energy) | | | |
| 1. Strict marginal energy cost (not to be adjusted) | – | X | X |
| 2. Coincident demand charge (i.e., on maximum kW in peak hours only) | | | |
| a. marginal cost of generation capacity | LOLP-based allocation to peak period. Recovered through energy or demand charge. | | LOLP-based |
| b. marginal cost of network capacity - transmission (VHV, HV) cost | 100% recovery through energy charge or demand charge | | – |
| - distribution (MV, LV) cost | – | X | X |
| 3. Simple maximum demand charge (i.e., on maximum kW in all hours) | | | |
| a. marginal cost of generation capacity | – | LOLP-based | LOLP-based |
| b. marginal cost of network capacity - transmission (VHV, HV) cost | 100% recovery, preferably through energy charge | | – |
| - distribution (MV, LV) cost | Either 100% in demand charge or recovered fully through peak and off-peak energy charge. | | |
| B. Pure energy tariff (no demand charge) | | | |
| 1. Marginal energy cost | – | On-peak strict marginal energy cost | Off-peak strict marginal energy cost |
| 2. Marginal capacity costs a. marginal cost of generation capacity | – | LOLP-based share of generation capacity cost | LOLP-based share of generation capacity cost |
| b. marginal cost of network capacity - transmission (VHV, HV) cost | – | 100% recovery through energy charge | |
| - distribution (MV,LV) cost | – | Recovery spread equally across all kWh in peak and off peak periods | |

the peak period), or 2) a simple maximum demand charge (i.e., one that is based on the maximum kW in any hour of the month) is used.

If a ***coincident demand charge*** is applied:

a) the portion of the marginal cost of generation capacity allocated to the peak hours can be recovered through a separate demand charge or through the energy charge. On a system with a broad peak period, recovering these costs through the separate demand charge may be preferable. Often, however, the use of an energy charge is understood better than the use of a demand charge.

b) the marginal cost of network capacity associated with transmission (VHV and/or HV) can be properly recovered through either the peak energy charge or the demand charge. It is assumed that these costs are related to serving peak, and should not be borne by off-peak use.

c) it is desirable that the marginal cost of network capacity related to distribution (MV and/or LV) should be spread equally over all kWh (both peak and off-peak). This prevents a customer from avoiding all costs associated with the local distribution system, by limiting his usage to only the off-peak hours. Other costs further up the system (i.e., transmission and generation capacity costs) avoided by limiting usage to the off-peak hours are freed to serve new load. However, local facilities not used during peak hours are of little or no use to serve other load. These costs could be avoided if they were to be included in a peak period demand charge.

Alternatively, if a ***simple maximum demand charge*** is applied:

a) the portion of the marginal cost of generation capacity allocated by LOLP to the peak period should be spread across all kWh in that period.

b) the marginal cost of network capacity related to transmission (VHV and/or HV) should be recovered through the peak period energy price.

c) the local facilities cost (MV and/or LV) can be recovered through either the demand charge or spread equally across all kWh in the year. With a simple maximum demand charge, these costs would not be avoided by peaking during the off-peak hours. While recovering these costs through the demand charge is desirable, this cost component alone may not be sufficient to justify the additional complication and expense of a separate demand charge.

In theory, a simple maximum demand charge-based tariff design is totally contrary to the philosophy underlying TOD tariffs. From a practical standpoint as well, this option is largely irrelevant in today's metering environment, where TOD metering of energy and demand can be accomplished with one meter and at a cost that is not significantly different than the cost of TOD energy-only metering.

We recommend a phased program of transition that replaces all simple maximum demand to coincident demand billing with coincident demand billing within the next three years. We have included simple maximum demand tariff designs in this report to cover the period of transition.

### 12.5.3 Basis for Demand Charge

A discussion of the appropriate use of a separate demand charge has been incorporated into the explanation of the peak and off-peak energy price. However, an additional discussion may be helpful.

As is often the case when incorporating cost analysis into rate design, there is an inherent conflict between short-run and long-run considerations. In the case of generation capacity cost, recovering this cost through a separate demand charge may result in a more appropriate short-run price signal, while recovering these costs through the energy charge may give a more appropriate long-run price signal. (In the short run, a large portion of cost is fixed, while in the long run, all costs are variable.)

Other factors to be considered when making the decision on the use of a demand charge include:

- seasonal load variations
- duration of daily peak period
- metering cost
- customer understanding and acceptance
- probability of shifting peak or off-peak period rather than reducing peak
- probability of creating an even higher "needle" peak in the peak period (if the probability is high, use a separate demand charge)
- variation of load and cost between peak and off-peak periods.

These and other factors must be carefully weighed when rates are designed. A delicate balance between economic efficiency, fairness and practicality must be achieved.

It is current Polish practice to divide the demand charge into two components -- contract demand and measured (recorded) demand. A contract component places slightly more emphasis on revenue stability (i.e., the distribution company knows that this revenue is coming) while a single demand charge (particularly a coincident one) places more emphasis on load management objectives. While there is excess system capacity, emphasis on revenue stability is reasonable. We therefore recommend preserving this two-part demand charge in the 1994 tariffs.

The rationale behind the contract demand charge component applied here is called "minimum network cost." The concept is that there are "fixed" and "variable" components to marginal network capacity costs. The former costs (e.g., costs of primary feeders to customers, associated substation transformer capacity) should be collected even if the facilities are not used by the customers for which they are intended, while the latter costs are for facilities that can be utilized to serve other load.[2]

The advantage of the two-component demand charge is that it is already understood by customers. Further, during the current period of industrial restructuring, the "fixed" contract component helps to stabilize revenues. In the near term, however, PPGC should consider rolling all capacity costs into a single measured demand charge. This "pay as you go" approach provides large customers with greater incentive to manage their load. The single demand charge can easily be derived from the tariff structures presented in the following pages. If revenue stability remains a concern, a "ratchet" clause in the demand charge, which relates minimum billing demand to peak-month demand, may be applied.

The level of the contract demand charge is taken as 50 percent of the cost of network capacity on the customer's own-voltage. Thus, for example, a customer served at HV (tariff "A") would pay half of the HV network capacity cost (after it is adjusted to the class revenue responsibility) as a contract charge.

The contract charge is further adjusted downward from strict marginal capacity cost to reflect empirical data indicating that declared contract demand has historically exceeded measured demand, as summarized in the following table.

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[2] Unfortunately, the precise share of costs that are "fixed" is location-specific. For typical customers, we know that these costs are certainly less than 100 percent of own-voltage capacity cost, but we do not know exactly how much less. We have estimated that 50 percent of own-voltage capacity cost should not be avoided. Note that the rationale for the contract demand charge is the same as discussed above with respect to distribution network (MV and/or LV) capacity costs, i.e., that certain investments in the network are user-specific local facilities that should not be avoided even if a customer's peak is not within the peak period.

| Tariff Class | Historical Ratio of Contract to Measured Demand | | | Ratio Assumed in this Study |
|---|---|---|---|---|
| | 1991 | Jan-Jun 1992 | October 1992 | |
| "A" (HV) | 1.28 | 1.23 | 1.20 | 1.10 |
| "B" (MV) | 1.86 | 1.80 | 1.68 | 1.50 |
| "C2" (LV) | 2.03 | 1.98 | 1.97 | 1.60 |

### 12.5.4 Proposed Tariff Design Structure

The foregoing TOD tariff-setting philosophy has been applied in the following manner. First, all tariff classes have been allocated TOD energy charges based on strict long-run marginal cost. Then, marginal capacity costs have then been scaled downward until total charges match class revenue requirements. Finally, these capacity costs have been allocated as demand or energy charges according to the considerations outlined above.

#### Tariff "G" - Residential

The most important issue with regard to the residential tariff is to reduce the magnitude of the subsidy involved at present. Two options are proposed, paralleling current tariffs "G11" (flat energy charge) and "G12" (TOD energy charge). Each option collects the class revenue target yield of 828.9 Zl/kWh (mid-1992 prices), assuming an average load factor of .25 and a coincidence factor of 0.49. These options are summarized in Exhibit 12-8 and representative bill impacts are presented in Exhibit 12-9.

This tariff is applicable to all residential and small farm households. It is presumed that most households will continue to be billed on a flat-rate energy charge. For the optional two-period TOD rate, the peak period includes all peak and mid-peak hours of the week; the mid-day valley and all other hours are off-peak.

Given the fact that an overall real yield increase of 15 percent is required to achieve revenue responsibility (see Exhibit 12-6), it is considered reasonable to expect that the historically low residential tariff accept a somewhat higher increase. Therefore, it was decided not to use cross-subsidies from other classes as a means to moderate the proposed

**Exhibit 12-8**
**Proposed Tariff "G" (Residential) Structure**

| Tariff "G" | | Energy (Zl/kWh) | | |
|---|---|---|---|---|
| Option | Season | Peak | Mid-Peak | Off-Peak |
| G12 | Winter | 1.149 | | 484 |
| | Summer | 1.106 | | 531 |
| G11 | Winter | 830 | | |
| | Summer | 830 | | |

**Exhibit 12-9**
**Typical Bill Impacts: Tariff "G" (Residential)**

| Consumption kWh/kW/mo | TOD Energy Shares | | Bill Impact (tysZl/kW/month) | | |
|---|---|---|---|---|---|
| | Peak | Mid-Peak | Present | Proposed | % Change |
| 200 | 0.27 | 0.25 | 126.200 | 165.936 | 31% |
| 200 | 0.32 | 0.30 | 126.200 | 177.823 | 41% |
| 200 | 0.22 | 0.20 | 126.200 | 154.049 | 22% |
| 100 | 0.27 | 0.25 | 63.100 | 82.968 | 31% |
| 100 | 0.32 | 0.30 | 63.100 | 88.912 | 41% |
| 100 | 0.22 | 0.20 | 63.100 | 77.024 | 22% |
| 400 | 0.27 | 0.25 | 252.400 | 331.872 | 31% |
| 400 | 0.32 | 0.30 | 252.400 | 355.646 | 41% |
| 400 | 0.22 | 0.20 | 252.400 | 308.098 | 22% |

tariff increase to residential users. When comparing the flat-rate tariff with current rates, the proposed real increase is approximately 60 percent (at mid-1992 prices).

As noted in Section 12.2, if it is concluded that this rate increase would impose too great a burden on low-income users, we would suggest a three-block tariff instead. Under this option (not quantified here), the tail block is priced to reflect strict LRMC. Once this is fixed, the prices for the first two blocks would be adjusted until the desired yield (revenue responsibility) is achieved. Under this option, the subsidized block would be charged at a minimum the strict long run marginal cost of off-peak energy.

The residential tariff currently includes group accommodation facilities (e.g., dormitories, schools, orphanages, etc.). As residential tariffs are increased toward marginal costs, other low-voltage tariffs may be more advantageous for these consumers, and they should be encouraged to consider options available in tariff class "C."

A point worth noting here relates to the very small difference in class revenue-neutral LRMC between residential (tariff "G") and other LV classes (tariffs "C1" and "C2"). Since all of these classes are served at low voltage, the differences result from differing assumptions regarding coincidence factor, load factor, and rating period energy shares. The results are based on limited available load research and the judgment of the study team. Uncertainty regarding these fundamental assumptions highlights the importance of and critical need for additional load research on electricity consumption patterns in Poland.

### Tariff "A" - High Voltage

This proposed tariff is to be applied for all electricity consumption of customers served at high voltage.

Currently, tariff "A" customers (approximately 400) are given the option, subject to engineering constraints, of a coincident or a maximum demand charge, and a flat or TOD energy charge. As soon as feasible, all of these customers should be on a mandatory two-part time-of-day (TOD) tariff with a coincident demand charge.

Tariff options are summarized in Exhibit 12-10. Assuming an average class load factor of 0.6 and representative TOD energy shares (0.17 peak and 0.27 mid-peak), these tariff structures would meet a class revenue responsibility of 416.4 Zl/kWh. The demand and energy charges have been aligned closely with the economic cost of supply.

Exhibit 12-10
Proposed Tariff "A" (High Voltage) Structure

| Tariff "A" | | Demand (tysZl/kW/mo) | | Energy (Zl/kWh) | | |
|---|---|---|---|---|---|---|
| Option | Season | Contract | Measured | Peak | Mid-Peak | Off-Peak |
| A23 | Winter | 6.790 | 36.580 | 752 | 352 | 210 |
| | Summer | 6.790 | 33.260 | 542 | 472 | 225 |
| A22 | Winter | 6.790 | 36.580 | 508 | | 210 |
| | Summer | 6.790 | 33.260 | 494 | | 225 |
| A21 | Winter | 6.790 | 36.580 | 335 | | |
| | Summer | 6.790 | 33.260 | 342 | | |

Note: Tariffs based on coincident demand.

Typical bill impacts are illustrated in Exhibit 12-11. Of course, actual bill impacts can vary widely, depending on individual customer characteristics, including load factor, energy shares by rating period, etc. Since the proposed structure is similar to the existing structure, the data do not show a marked difference in impact across a range of load factors and patterns of energy use.

It is probable that obligatory implementation of TOD pricing will require time for various preparatory activities, including meter procurement, testing, calibration, implementation, training of meter readers and testers, altering billing procedures, etc. This process is likely to take up to a year. In the interim, it may be necessary to continue offering a two-part tariff structure based upon a simple maximum demand charge (i.e., a non-coincident demand-based charge) and a flat energy charge. Representative tariff structures are shown in Exhibit 12-10.

### Tariff "B" - Medium Voltage

This tariff is to be applied to all customers -- currently about 27,000 -- served at medium voltage.

**Exhibit 12-11**
**Typical Bill Impacts: Tariff "A" (High Voltage)**

| Load Factor | Consumption kWh/kW/mo | TOD Energy Shares | | Bill Impact (tysZl/kW/month) | | |
|---|---|---|---|---|---|---|
| | | Peak | Mid-Peak | Present | Proposed | % Change |
| 0.60 | 438 | 0.16 | 0.27 | 169.827 | 182.702 | 8% |
| 0.60 | 438 | 0.19 | 0.32 | 169.827 | 193.322 | 14% |
| 0.60 | 438 | 0.13 | 0.22 | 169.827 | 172.082 | 1% |
| 0.40 | 292 | 0.16 | 0.27 | 123.318 | 133.247 | 8% |
| 0.40 | 292 | 0.19 | 0.32 | 123.318 | 140.327 | 14% |
| 0.40 | 292 | 0.13 | 0.22 | 123.318 | 126.166 | 2% |
| 0.80 | 584 | 0.16 | 0.27 | 216.335 | 232.157 | 7% |
| 0.80 | 584 | 0.19 | 0.32 | 216.335 | 246.317 | 14% |
| 0.80 | 584 | 0.13 | 0.22 | 216.335 | 217.997 | 1% |

The recommended tariff design is defined in Exhibit 12-12. Again, a mandatory, two-part TOD tariff based on a coincident demand charge is recommended. Interim tariff structures based on a maximum demand charge are also presented. Based upon an average class load factor of 0.42 and assumed rating period energy shares (0.18 peak and 0.31 mid-peak), these tariff structures are adequate for the desired revenue responsibility of 547 Zl/kWh. Representative bill impacts are shown in Exhibit 12-13.

### Tariff "C2" - Low Voltage > 40 kW

This tariff should be applied to all non-residential customers served at low voltage whose maximum demand is over 40 kW or whose consumption exceeds 80 GWh. These customers (estimated to be about 25,000) are predominantly small industries.

Again, two-part tariffs are recommended, with a pure energy tariff option. For low-voltage service, it is reasonable to permit customers flexibility with regard to tariff structure (coincident or maximum demand charge; one, two, or three rating periods for energy



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## Exhibit 12-12
## Proposed Tariff "B" (Medium Voltage) Structure

| Tariff "B" | | Demand (tysZl/kW/mo) | | Energy (Zl/kWh) | | |
|---|---|---|---|---|---|---|
| Option | Season | Contract | Measured | Peak | Mid-Peak | Off-Peak |
| B23 | Winter | 11.560 | 33.760 | 884 | 457 | 277 |
| | Summer | 11.560 | 31.780 | 644 | 574 | 303 |
| B22 | Winter | 11.560 | 33.760 | 620 | | 277 |
| | Summer | 11.560 | 31.780 | 599 | | 303 |
| B21 | Winter | 11.560 | 33.760 | 442 | | |
| | Summer | 11.560 | 31.780 | 448 | | |

Note: Tariffs based on coincident demand.

## Exhibit 12-13
## Typical Bill Impacts: Tariff "B" (Medium Voltage)

| Load Factor | Consumption kWh/kW/mo | TOD Energy Shares | | Bill Impact (tysZl/kW/month) | | |
|---|---|---|---|---|---|---|
| | | Peak | Mid-Peak | Present | Proposed | % Change |
| 0.42 | 307 | 0.18 | 0.31 | 151.743 | 168.075 | 11% |
| 0.42 | 307 | 0.22 | 0.37 | 151.743 | 177.594 | 17% |
| 0.42 | 307 | 0.14 | 0.25 | 151.743 | 158.557 | 4% |
| 0.20 | 146 | 0.18 | 0.31 | 91.629 | 96.572 | 5% |
| 0.20 | 146 | 0.22 | 0.37 | 91.629 | 101.105 | 10% |
| 0.20 | 146 | 0.14 | 0.25 | 91.629 | 92.040 | 0% |
| 0.60 | 438 | 0.18 | 0.31 | 200.927 | 226.578 | 13% |
| 0.60 | 438 | 0.22 | 0.37 | 200.927 | 240.176 | 20% |
| 0.60 | 438 | 0.14 | 0.25 | 200.927 | 212.980 | 6% |

charges). Various options pegged to the class revenue responsibility are presented in Exhibit 12-14. Typical bill impacts are shown in Exhibit 12-15.

### Tariff "C1" - Low Voltage < 40 kW

This tariff should be applied to all non-residential customers served at low voltage whose maximum demand is under 40 kW or whose consumption is less than 80 GWh. There are more than 1.1 million customers in this class, including commercial and service facilities, entertainment establishments, offices, hotels, etc.

Again, two-part tariffs are recommended, with a pure energy tariff option. Due to the large number of customers and their diversity, it is reasonable to permit customers flexibility with regard to tariff structure (coincident or maximum demand charge; one, two, or three rating periods for energy charges). Various options pegged to the class revenue responsibility are presented in Exhibit 12-16. Typical bill impacts are shown in Exhibit 12-17.

### Street Lighting Tariff

Street lighting was eliminated as a separate tariff class in the most recent tariff revision. It is recommended that the class be re-instituted. Whenever a sizeable customer group with a unique and identifiable consumption pattern can be classified, we believe that it should be charged for these characteristics rather than those associated with other customers. There are currently about 100,000 public lighting accounts.

The recommended street lighting tariff is shown in Exhibit 12-18. This tariff is designed to recover class revenue responsibility. It is understood that the capital and O&M costs associated with the installation of street lighting -- poles, fixtures, luminaries, photovoltaic cells, conductors, etc. -- are directly borne by the respective public authorities concerned. Consequently, the tariff is intended to recover only the cost of generation and distribution of electricity.

## Exhibit 12-14
## Proposed Tariff "C2" (Low Voltage > 40 kW) Structure

| Tariff "C2" (>40 kW) | | Demand (tysZl/kW/mo) | | Energy (Zl/kWh) | | |
|---|---|---|---|---|---|---|
| Option | Season | Contract | Measured | Peak | Mid-Peak | Off-Peak |
| C223 | Winter | 5.930 | 17.240 | 1.152 | 660 | 448 |
| | Summer | 5.930 | 16.530 | 860 | 787 | 483 |
| C222 | Winter | 5.930 | 17.240 | 847 | | 448 |
| | Summer | 5.930 | 16.530 | 813 | | 483 |
| C221 | Winter | 5.930 | 17.240 | 640 | | |
| | Summer | 5.930 | 16.530 | 645 | | |
| C213 | Winter | - | - | 1.365 | 912 | 451 |
| | Summer | - | - | 1.087 | 1.020 | 483 |

Note: Tariffs based on simple maximum demand.

## Exhibit 12-15
## Typical Bill Impacts: Tariff "C2" (Low Voltage > 40 kW)

| Load Factor | Consumption kWh/kW/mo | TOD Energy Shares | | Bill Impact (tysZl/kW/month) | | |
|---|---|---|---|---|---|---|
| | | Peak | Mid-Peak | Present | Proposed | % Change |
| 0.31 | 226 | 0.18 | 0.31 | 177.153 | 171.834 | -3% |
| 0.31 | 226 | 0.22 | 0.37 | 177.153 | 179.857 | 2% |
| 0.31 | 226 | 0.14 | 0.25 | 177.153 | 163.811 | -8% |
| 0.20 | 146 | 0.18 | 0.31 | 130.922 | 120.219 | -8% |
| 0.20 | 146 | 0.22 | 0.37 | 130.922 | 125.396 | -4% |
| 0.20 | 146 | 0.14 | 0.25 | 130.922 | 115.043 | -12% |
| 0.50 | 365 | 0.18 | 0.31 | 257.005 | 260.986 | 2% |
| 0.50 | 365 | 0.22 | 0.37 | 257.005 | 273.927 | 7% |
| 0.50 | 365 | 0.14 | 0.25 | 257.005 | 248.045 | -3% |

## Exhibit 12-16
## Proposed Tariff "C1" (Low Voltage < 40 kW) Structure

| Tariff "C1" (<40 kW) | | Demand (tysZl/kW/mo) | | Energy (Zl/kWh) | | |
|---|---|---|---|---|---|---|
| Option | Season | Contract | Measured | Peak | Mid-Peak | Off-Peak |
| C123 | Winter | 6.090 | 17.680 | 1.133 | 673 | 462 |
| | Summer | 6.090 | 16.970 | 858 | 801 | 501 |
| C122 | Winter | 6.090 | 17.680 | 854 | | 462 |
| | Summer | 6.090 | 16.970 | 822 | | 501 |
| C121 | Winter | 6.090 | 17.680 | 663 | | |
| | Summer | 6.090 | 16.970 | 669 | | |
| C113 | Winter | - | - | 1.347 | 922 | 467 |
| | Summer | - | - | 1.084 | 1.032 | 503 |
| C112 | Winter | - | - | 1.088 | | 467 |
| | Summer | - | - | 1.051 | | 503 |
| C111 | Winter | - | - | 789 | | |
| | Summer | - | - | 789 | | |



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Exhibit 12-17
Typical Bill Impacts: Tariff "C1" (Low Voltage < 40 kW)

| Load Factor | Consumption kWh/kW/mo | TOD Energy Shares | | Bill Impact (tysZl/kW/month) | | |
|---|---|---|---|---|---|---|
| | | Peak | Mid-Peak | Present | Proposed | % Change |
| 0.31 | 226 | 0.20 | 0.32 | 175.269 | 178.447 | 2% |
| 0.31 | 226 | 0.24 | 0.38 | 175.269 | 192.185 | 10% |
| 0.31 | 226 | 0.16 | 0.26 | 175.269 | 164.708 | -6% |
| 0.20 | 146 | 0.20 | 0.32 | 113.077 | 115.127 | 2% |
| 0.20 | 146 | 0.24 | 0.38 | 113.077 | 123.990 | 10% |
| 0.20 | 146 | 0.16 | 0.26 | 113.077 | 106.263 | -6% |
| 0.50 | 365 | 0.20 | 0.32 | 282.693 | 287.817 | 2% |
| 0.50 | 365 | 0.24 | 0.38 | 282.693 | 309.976 | 10% |
| 0.50 | 365 | 0.16 | 0.26 | 282.693 | 265.659 | -6% |

Exhibit 12-18
Proposed Street Lights Tariff

| Street Lights Tariff | | Energy (Zl/kWh) | | |
|---|---|---|---|---|
| Option | Season | Peak | Mid-Peak | Off-Peak |
| - | Winter | 788 | | |
| | Summer | 788 | | |



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## 12.6 OPTIONAL INTERRUPTIBLE TARIFFS

At some point in the future after today's excess system capacity is absorbed, distribution companies should consider the introduction of interruptible tariffs on an optional basis. The potential class of such customers -- typically a subset of tariff classes "A" and "B" -- will have to be determined based upon a detailed market survey and the considerations outlined in the following.

Interruptible service (IS) is a demand-side option that is widely used and accepted by electric utilities and utility customers in many countries. Interruptible service allows a utility to interrupt load to a customer in accordance with specified provisions. For this privilege, the utility reduces the customer's bill by a specified amount each month. In regard to the daily operations of generation facilities, IS improves reliability and operating flexibility. In the longer term, IS allows the utility to build less generating capacity. A well designed IS tariff provides substantial benefits to both the utility and the customer.

Under an IS tariff, the customer contracts with the utility for an amount of load the customer is willing to remove from the system when requested to do so. This load is then considered to be non-firm. The IS tariff will specify an advance notice period that may be as long as 24 hours to as little as 15 minutes. While the utility may, in some cases, have direct control over the customer's load, most often the interruption is triggered by a phone call from the utility to the customer. This requires a dedicated phone line which is manned constantly to ensure timely communication. Special metering equipment that records usage on a continuous basis is also required to ensure compliance with the magnitude and time of requested interruption.

As mentioned earlier, IS allows the utility to install less generating capacity while maintaining a target level of reliability. Since IS can be called for a limited number of hours, it displaces peaking capacity in the generation mix. Therefore, the interruptible credit given to the customer should be based on the long-run marginal cost of peaking capacity, generally assumed to be combustion turbines (CT). While the credit should be *based* on this cost, it may *not equal* the LRMC of a CT because the IS capacity may not be of equal value to the utility as the same amount of CT capacity. For example, an IS tariff that allows only 100 hours per year of interruption would not be as valuable to the utility as a CT that can run 2,000 or more hours per year. In this case, the $/kW credit for IS should be less than the same $/kW LRMC of a CT.

The IS tariff should include specification of the interruption period. Generally, a maximum number of hours of interruption per year, week, and day will be given. This provision has a major impact on the value of the IS to the utility.



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The IS tariff should include a substantial penalty for non-compliance. The utility has foregone building capacity and paid significant amounts to the customer for the right to interrupt the load. Customers must be discouraged from contracting for non-firm load and receiving credits when they have little intention or ability to interrupt load.

Since the influence of IS has a long-term impact on the utility's generation expansion plan, a three-year notice of contract cancellation on the part of the customer may be appropriate. Specification of the various parameters of an interruptible tariff would begin with the consideration and types of calculations discussed above. Once a preliminary menu of interruptible tariffs is developed on this basis, it is necessary to conduct a survey of the target population to test the concept. Information gathered in this process can be valuable in subsequently "fine tuning" the preliminary menu. Some of this preliminary research is currently in progress as part of the demand side management (DSM) program being conducted for PPGC by Hagler, Bailly.

## 12.7 OTHER TARIFF CONSIDERATIONS

The objective of this study is to identify appropriate levels and structures for electricity pricing-of power purchases, bulk transactions and retail final sales- at the national level. The study cannot address the myriad of special terms and agreements between and among individual generators, PPGC, distributors, and final consumers. In short, the detailed principles governing the settlement of accounts between entities in the power sector are not superseded. Likewise, specialized billing principles such as outlined in the Price List No.7-Z/92 (e.g., service rates, penalty provisions, and charges for reactive energy, overcurrent protection, and increased service reliability should continue to be applied in the context of revised tariff structures and levels.

Having noted the limit of this study, this section contains a brief discussion of other considerations beyond the basic tariff class structures defined in the foregoing pages.

### Reactive Energy

Currently, high and medium voltage (as well as some low voltage) customers can be charged for the consumption of reactive energy when consumed at a sub-optimal level for the system. The charge is billed as a percentage surcharge to the value of the active energy consumed. The result is a progressive scale of payments for power factors below 0.93. While this system

is being implemented successfully, we understand that there have been complaints that it is not a rational fee, possibly due to a misunderstanding of its basis.

One possible alternative to the present system would be to require customers consuming potentially high levels of reactive energy to be billed on the basis of kVa rather than kW. Structuring the demand charge in this manner provides a built-in incentive for power factor improvement. To illustrate, the proposed Winter demand charge for tariff "A" is 36,580 Z1/coincident kW; alternatively, a demand charge of 32,920 Z1/coincident kVa could be offered. A customer who maintains the desired power factor (assumed to be 0.90 for this example), would see no adverse bill impact. On the other hand a customer with a lower power factors would be penalized. Further, any customer who is able to improve power factor beyond the target level will see a bill reduction. Additionally, distributors will benefit through reduction in line losses.

This alternative billing procedure would require additional investment in metering, but it would offer the advantage of a more transparent methodology with positive incentives.

### Supply Reliability

Currently customers who request and receive a higher degree of reliability than the standard (which is based on a single independent supply sequence), are charged a multiple of the demand charge specified for their tariff class. The multiple is a factor of 1.5 for two separate supply sequences and 2.0 for three or more independent sequences.

In concept, the current charges appear reasonable, and they offer the clear advantage of customer comprehension. The disadvantage of simple multiples is that they do not incorporate specific customer circumstance, and may therefore over-or under-recover the cost of providing increased supply reliability. For example, the charge should certainly be dependent on the extent to which the customer-supplied equipment is used for improving reliability of supply. In general, while it may be appropriate to offer a standard "factor", we would encourage negotiations with individual customers permitting charges which are more closely linked to the incremental cost of providing additional supply reliability.

### Special Agreements with Customers

Special agreements with customers are currently permitted when particular conditions dictate, e.g., when the customer has his own generating units, or when his industrial requirement is especially sensitive to the conditions of supply.

Adapting tariffs to local circumstances is entirely appropriate, so long as the principles underlying negotiations are consistent with the principles of marginal cost pricing which have been employed in setting standard rates by tariff class. Class tariff should be the starting point of these negotiations; subsequent adjustments can then be made to more accurately reflect the marginal cost of providing service under the specific circumstances of the customer.

### Load Research

To facilitate future tariff revisions, we suggest that PPGC and the distribution companies expand currently available load research data to develop on-going additional survey data on customer load shapes, coincidence factors, peak energy shares, and load factors for each tariff class, as well as for the typical customer segments within each class.

there is a need to put in place a well designed and on-going load research program. This could be done through a contract with an organization such as the Power Engineering Institute, or through internal staffing. Such a program should be based upon a sample design that can support the development of statistically valid estimates for the types of data noted above, with a degree of precision that conforms to load research norms in the industry today. While useful *ad hoc* load research activities have been conducted, these are not certain to provide an on-going basis for developing estimates of key variables, noted above, that are essential in tariff planning, load forecasting, and system planning.

# CENTRAL AND EASTERN EUROPE
# REGIONAL ENERGY EFFICIENCY PROJECT
# EUR-0030-C-00-2053-00

**Energy Pricing, Energy Efficiency, and**
**Energy Sector Restructuring Component**

**Poland**
**Integrated Resource Planning (IRP)**

*Task Completion Memorandum*

*Prepared for:*

U.S. Agency for International Development
Bureau for Europe and NIS
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Energy and Infrastructure Division

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# CENTRAL AND EASTERN EUROPE
# REGIONAL ENERGY EFFICIENCY PROJECT

*Task Completion Memorandum*

## *Poland - Integrated Resource Planning*

### Summary Task Description

This task was designed to provide assistance to the Polish Power Grid Company (PPGC) and other relevant parties in Poland to develop a process and capabilities for integrated resource planning (IRP), which would combine the results of load forecasting, demand-side management (DSM), electricity supply planning, and tariff studies. The work focused on developing analytical, computer modeling, and organizational capabilities that support the appraisal of multilateral development bank (MDB) power sector loans on an IRP basis.

### Specific Goals and Objectives

The Poland Integrated Resource Planning Task had the following goals and objectives:

- To introduce integrated resource planning as the basis for power sector planning in Poland;
- To assist PPGC to establish an organizational capability to carry out IRP activities;
- To provide a computer model for utility planning based on IRP concepts and analytical methodologies; and
- To support the appraisal of MDB power sector loans on an IRP basis.

## Expected Outputs

*Activity 1: Introduce Integrated Resource Planning Model*

PPGC has an IRP model licensed and installed, with which it can incorporate available data for utility planning purposes to support appraisal of MDB power sector loans.

*Activity 2: Develop IRP Action Plan*

PPGC prepared an IRP Action Plan that meets the requirements of the World Bank's power transmission loan to the Government of Poland.

*Activity 3: Provide Management Training on IRP Issues*

Through training of relevant personnel from Polish power sector organizations, IRP has become a well-known topic in Poland's power sector.

## Deliverables

As the result of the preceding activities, Hagler Bailly produced the following deliverables:

- One institutional development study was undertaken which resulted in a detailed roadmap for the development and implementation of IRP at PPGC.
- One copy of the selected IRP computer software model was licensed for use by PPGC, including training and support.
- Six seminars were produced at PPGC on topics related to IRP.
- PPGC received assistance in arranging a visit to two U.S. utilities on IRP topics.
- A Task Completion Memorandum was written that summarized the work of this task. Five copies of the report were submitted to USAID.

## Results and Next Steps

The USAID IRP Project supported work with a Polish utility counterpart organization, the Polish Power Grid Company (PPGC) and accomplish the following tasks (deliverables):

- **Institutional Policy Development**. Through a number of executive management seminars and policy papers, IRP concepts were communicated to high level officials in Poland's government and energy sector. As a result, provisions were included in the draft Energy Law (November 1994 version, amended February 1995) for energy enterprises to conduct IRP (Article 19).

- **Establishment of IRP Unit at PPGC**. In the first tranche of World Bank lending for PPGC's transmission system, a loan condition required PPGC to complete an IRP Action Plan by June 1994 and establish an IRP unit within the company by December 1994. These activities were accomplished, which included the provision of a software license and training for the Integrated Planning Model, a state-of-the-art utility IRP tool. PPGC senior management also received executive training, including an extensive IRP study tour in the U.S. One of the results was PPGC's competitive solicitation of supply-side bids from generators in November 1994, which established a market-determined avoided generation cost of US$ 0.036/kWh.

This bidding process and results framed the next step that PPGC anticipated taking in 1995 which was to solicit comparable competitive bids for demand-side resources.

# INTEGRATED RESOURCE PLANNING

# ACTION PLAN FOR POLAND

**Draft**
**Advisory Memoranda**

**Prepared by RCG/Hagler Bailly**
**For the Polish Power Grid Company**

**Prepared Under:**
**Eastern Europe Regional Energy Efficiency Project**
**U.S. Agency for International Development**
**Washington, DC**

**17 June 1994**
**Warsaw, Poland**

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**INTEGRATED RESOURCE PLANNING**
**ACTION PLAN FOR POLAND**

**Draft**
**Advisory Memoranda**

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# SECTION 1

# INTRODUCTION

The Energy Sector Restructuring, Privatization, and Regulatory Reform Program of the Government of Poland, which is currently underway, aims to:

- liberalize energy prices and eliminate subsidies as far as possible;
- promote enterprise competition through the elimination of barriers to market entry in all productive sectors which are not "natural monopolies;" and
- transform the governance, ownership and control, and regulation of state-owned enterprises through the adoption of a market economy and privatization.

These reforms are expected to revitalize the energy sector, enhance its long-term financial viability, and encourage economically optimal investment and consumption decisions. The program is being conducted with the assistance of the World Bank, the United States Agency for International Development (USAID), and other bilateral agencies.

In order to guide the future development of Poland's power sector, the Energy Sector Program includes an integrated resource planning (IRP) component through which both supply-side and demand-side resources are being identified to produce a mix of electric resources which yield the least cost to utilities, their customers, and society at large. Several teams are contributing to the development of the integrated resource plan. A number of Polish organizations, e.g., the Polish Academy of Sciences and the Polish Institute of Power Engineering, have undertaken electricity load forecasts. A USAID Electricity Transfer Pricing and Retail Tariff Study was completed that formulated an electricity tariff strategy. A French team completed a Transmission System Plan and an Austrian team worked on a Supply-Side Development Plan. Another USAID team identified and assessed demand-side management (DSM) resources.

The next step is to formulate an integrated resource plan using the results of these and other studies. It is anticipated that the integrated resource plan will be the basis for power sector loans from the World Bank and other multilateral development banks (MDBs), such as the US$ 800 million tranche of the World Bank loan that is set for appraisal in 1995.

In anticipation of that appraisal, the World Bank and the Polish Power Grid Company (PPGC) agreed to create an IRP unit, in an *Aide Memoire* of November 3, 1993 relevant to the $225 million transmission sector tranche. PPGC agreed to prepare a comprehensive proposal in this **IRP Action Plan** by June 30, 1994 and to implement the IRP unit by December 31, 1994. This **IRP Action Plan** provides PPGC with a detailed roadmap for the development and implementation of the IRP unit. The **IRP Action Plan** focuses on developing analytical, organizational, and institutional capabilities at PPGC and in Poland that support MDB loan appraisals on an integrated resource planning basis.

Following are the topics presented:

- **Section 2** gives an overview of the fundamental concepts of IRP, including a discussion of how IRP can be developed and implemented within the context of Poland's emphasis on market solutions to power sector development.

- **Section 3** discusses the role of the IRP unit within the corporate strategy of PPGC and the institutional framework necessary for the IRP unit to function, including allocation of responsibility within PPGC for each element of the process and the role of outside agencies.

- **Section 4** identifies and describes the following elements of the IRP process, including terms of reference that define the steps that must be carried out to do each element:

  - Load forecasting;
  - Identification of both supply-side and DSM resources;
  - Transmission and distribution system planning;
  - Environmental considerations;
  - Plan integration;
  - Tariff design and power pricing aspects; and
  - Financial planning.

- **Section 5** presents the analytical framework for integrating these elements into a system development plan including:

  - Identifying the flow of information among the elements; and
  - Specifying the outputs from each element of the process.

- **Section 6** identifies the resources within PPGC and outside of PPGC necessary for IRP implementation, including:

  - Staffing requirements, including job descriptions and qualifications;
  - Subcontracting requirements;
  - Assessment of PPGC's in-house human resource capacity to undertake IRP-related activities and identification of training needs and facilities; and
  - Equipment and analytical tools.

- **Section 7** provides an approximate scheduling and critical path analysis of activities involved in each element of the IRP process, taking into account the iterative nature of the process.

- **Section 8** presents budgets for the implementation of the IRP process.

## SECTION 2

## INTEGRATED RESOURCE PLANNING

Integrated resource planning (IRP) is a comprehensive process through which utilities identify and acquire the most cost-effective electric resources necessary to meet their customers' incremental requirements for energy and power. IRP is a strategic planning process that provides significant changes to the way that utilities traditionally have conducted business.

IRP is often called "least-cost" planning, which refers to the acquisition of electric resources by utilities with the lowest possible cost to themselves, their customers, and society at large. "Electric resources" are available throughout the entire power system from the point of generation to the point of consumption. They include the traditional supply-side measures that provide megawatts from the construction of new generators, repowering and rehabilitating existing generation facilities, and purchasing power from wholesale markets or independent power producers. Electric resources also include measures that provide "negawatts" from efficiency improvements in generators (better heat rates), the transmission and distribution system (fewer line losses) and at the end-use (demand-side management).

In determining which are the most cost-effective resources to a utility, it is important to calculate costs and benefits properly. Utilities have traditionally calculated costs and benefits strictly from their own perspective. Thus, the benefits of a resource option (utility avoided operating and capital costs) would have to exceed its costs to the utility for the option to be cost-effective.

An important innovation of IRP is the inclusion of the costs and benefits of the utility's customers. For example, customer bill savings from demand-side management (DSM) add a large benefit that makes a number of energy efficiency measures cost-effective. Adding the customer's perspective to the cost/benefit analysis is increasingly important in economies like Poland's, which must be competitive in world markets.

Another innovation of IRP is the inclusion of benefits to society from the acquisition of electric resources that are relatively environmentally benign. The reduced social costs from reliance on technologies that create less pollution from the combustion of fossil fuels are increasingly important in a country like the Poland, which suffers environmental damages from power generation.

Electric resources in Poland should be systematically identified and acquired to be the lowest-cost options from the perspectives of the utility, its customers, and all society. This approach will yield the most economically-efficient outcome and will ensure the sustainable development of Poland's power system to meet current needs as well as those of future generations.

While IRP implies a "planning" activity, that is only one component of the entire process through which utilities systematically identify and acquire least-cost resources. The following

components of IRP are addressed below: 1) the power sector plan, 2) computer modeling to perform the quantitative analyses that support the plan, 3) resource acquisition activities that implement the plan, and 4) a system of incentives to motivate utilities to act in accordance with the plan.

**Developing the Power Sector Plan**

The basis for IRP is a plan that provides extensive analyses and recommendations for a course of action. Section 4 provides a detailed description of the IRP process proposed for implementation in Poland. Following is an outline of the steps of that process:

1. Identify the objectives of the plan (e.g., reliable service, minimal environmental effects, low cost of environmental controls, meeting peak demand in a cost-effective manner, and minimal bills for electricity customers).

2. Develop one or more load forecasts for different scenarios.

3. Determine the levels of capacity expected for each year of the plan.

4. Identify needed resources (e.g., fuels, generating capacity, transmission and distribution capacity, a manageable load shape, and demand reductions) needed to bridge the gap between expected loads and capacities.

5. Evaluate all of the electric resources in a consistent fashion and selecting the most promising resources for fashioning an effective, flexible, and responsive plan; and integrate methods of supplying power with methods for controlling and moderating demand.

6. Construct scenarios that project the selected mixes of resources against possible economic, environmental, and social circumstances.

7. Evaluate the economic and technical characteristics of each mix of resources and analyzing the uncertainties associated with the various scenarios.

8. Screen the alternatives to eliminate those that are not suitable and rank-ordering alternative courses of action.

9. Test each alternative for cost-effectiveness from a variety of perspectives (the utilities, ratepayers of different classes, and society at large).

10. Reevaluate the alternatives considering economic, environmental, and societal factors and select a plan for implementation that most nearly satisfies all the objectives of the plan.

11. Develop and implement a plan of action.

12. Monitor and evaluate the operation of the utilities under the plan and revising the plan if necessary.

## IRP Modeling

Utility planning is an intensely quantitative process that requires modern computer technologies to establish databases, analyze options, and present results in meaningful ways to decision makers. Most utilities have used large mainframe supply-side expansion models in the past. IRP models are relatively new on the scene and represent an important evolution in utility planning. The most important feature of IRP models is their ability to inherently evaluate specific supply-side and DSM resource options in a common analytical framework. Because these models are relatively new, they also provide state-of-the-art features, such as running on high-powered personal computers and work stations, providing "user-friendly" operational formats, and presenting high-quality graphical outputs. Section 5 details the analytical framework required for conducting IRP.

From a functional perspective, IRP models provide utility planners with the capability to literally integrate the results of a number of different models into one systematic analytical framework. For example, IRP models take as inputs the results of load forecast analyses, long-run marginal cost tariff studies, supply-side expansion plans, transmission and distribution plans, assessments of DSM potential, and production costing models. Most IRP models will accept the results of any number of other models as inputs. IRP models then produce an optimal mix of available utility assets to determine the type and timing of supply-side and DSM resources that best meet the demand forecast requirements over various time periods.

Two different analytical methods have evolved to conduct the resource selection process. The first method uses optimization models that incorporate dynamic programming techniques to evaluate all combinations of supply-side and DSM options. From this evaluation, an optimal plan is selected based on an objective function of minimizing revenue requirements or total resource costs (a good example is ICF Resources's Integrated Planning Model). The second method simulates a utility's chronological performance over long planning horizons and selects the most cost-effective options by ranking all alternatives available each year based on any combination of user-specified objective functions, e.g., minimizing total resource costs and rates (a good example is EPRI's IRP-Manager). Both kinds of IRP models facilitate the analysis of risk due to uncertainty in key assumptions through sensitivity and decision analysis techniques. They also allow financial analyses to calculate the impact of resource strategies on the utility's capital requirements, income statement, balance sheet, and source and use of funds. Additionally, these models enable consideration of the impacts that different resource strategies will have on the utility's revenue requirements and its customers' electricity tariffs.

Some utilities have gone half-way toward IRP modeling by conducting separate supply-side and DSM analyses using different models for each task. These models can be linked for purposes of data-sharing and conducting iterative analyses. The results of this approach can take two forms: 1) the subtraction of a cost-effective block of DSM resources from the load forecast; supply-side resources are then applied to the remaining load, and 2) the determination of separate blocks of cost-effective supply-side and DSM resources that meet the load forecast. While these results can provide a rough estimate of the relationship between cost-effective supply-side and DSM resources, they do not provide the necessary detail required of an IRP analysis.

This is because neither supply-side nor DSM resources are monolithic; they cannot be compared as blocks of potential resources, but must be disaggregated into their constituent parts. Just like a gas-fired combined cycle generator cannot be lumped together with a coal plant in a supply-side analysis, an industrial efficient motor program cannot be lumped together with a residential refrigerator efficiency program in a DSM analysis. The same concept applies to IRP: specific supply-side and DSM resources must be compared discretely, one against the other. Thus, IRP models do not operate in the same way as linked supply-side and DSM models because IRP models produce a rank-ordered resource mix that lists a combination of specific supply-side and DSM resources. This approach is essential for producing a meaningful investment plan and also for evaluating supply-side and DSM project proposals received in response to all-source competitive bidding programs (see below).

**Integrated Resource Acquisition**

In order for IRP to function properly in Poland, it is essential that utilities be given the authority to implement the plan, i.e., they should have the responsibility for acquiring both supply-side and demand-side resources according to the plan. "Acquiring" means arranging, directly or indirectly, for resources to be made available to the Polish electric system. A method for acquiring electric resources on an IRP basis has been developed in North America and is referred to as all-source competitive bidding. A specific approach to implementing all-source bidding in Poland is described in Section 3. A general description of this method of integrated resource acquisition follows.

Competitive bidding is a process that utilities can undertake to acquire electric resources through the marketplace. In a competitive bid, utilities solicit proposals for electric resources in an auction. The auction can take place periodically (for example once a year) or whenever the utility believes that resources are required, as the result of a comparison of load forecasts with supply plans. In the auction, proposals are typically solicited that must include the following characteristics:

- the amount of electric resources bid (GW and/or GWh)
- the bid price (in currency units per GW and/or GWh)
- a deadline or schedule to deliver the electric resources
- security for the delivery of the resources.

The utility then evaluates the proposals and ranks the bids based on a number of pre-established criteria, such as:

- the bid price
- non-price factors such as:
  - the experience and qualifications of the bidder in undertaking similar projects
  - the bidder's approach to project development and financing
  - the environmental impacts of the proposed project.

The utility then signs contracts with the winning bidders -- those that ranked the highest and that provide, in sum, the resource block required by the utility.

There are a number of variations on this theme. For example, utilities can conduct a bidding auction for generation resources, for improvements to the transmission and distribution (T&D) system, for DSM resources that improve end-use load management and efficiency, or for any combination or all of the above. The bidding process can be integrated, meaning that supply and DSM resources are acquired through the same auction, or through separate, parallel supply and DSM auctions. The supply block that the utility requests can be for power (GW), for energy (GWh), or for both. Eligible bidders can include the following:

- for generation resources: the utility's generation subsidiary, independent power producers (private non-utility generators), and the utility's large customers (cogenerators)

- for T&D improvements: the utility's T&D subsidiary and independent T&D engineering and construction management enterprises

- for DSM resources: the utility's distribution subsidiary, energy service companies (ESCOs), and the utility's large customers.

Finally, the payment that the utility makes to successful bidders can be made up front (a one-time payment for the delivered resource block) or over time (as the electric resources are actually delivered to the utility).

Integrated all-source bidding is a special case in which bids are solicited and accepted for all electric resources in a single auction. In this case, bids are evaluated with common selection criteria, without regard for whether the bid is for a supply or DSM resource. This approach to bidding creates a "level playing field" in which all bids are evaluated on a consistent basis as a method to implement a utility's integrated resource plan. Integrated all-source bidding also provides the benefit of being a market-based mechanism to identify and acquire electric resources, as compared to an approach that relies on the utility's own planning processes.

Competitive bidding has been employed by 84 utilities in North America over the last ten years. The results to date are quite notable in that roughly 20,000 MW of supply bids have been awarded through 116 auctions and 430 MW of DSM bids have been awarded through 30 auctions. Seventeen of those auctions were fully integrated.

Through the evaluation of many of the early bidding programs in North America, a number of lessons are generally accepted. On the supply-side, the approach was initially developed to control an over-development of the market for independent power. Nonetheless, many utilities continued to set the ceiling price for their auctions at their avoided cost, which in retrospect was too high. Thus, over-development of the market continued in some cases. On the other hand, the subsequent reduction of ceiling prices to a market clearing level has created some downward pressure on utilities' avoided costs. For example, in New York, avoided costs were redefined from an administrative calculation of the cost of utility generation, to the market's price of independent power generation. This trend has resulted in lower avoided costs.

A number of lessons have also been learned from DSM bidding programs. For example, while many of the early programs were open to both ESCOs and the utilities' large customers, the primary participant has been the ESCOs. DSM bid prices have ranged from $0.035 to $0.065/kWh, between 60 to 90% of utility avoided costs. It is generally recognized that ESCOs provide a "value-added" service compared to a utility's own DSM program offering, which has been valued at $0.005 to $0.025/kWh.

Lessons have also been learned from the integrated all-source bidding programs. One result is that it is clear that different selection criteria should be used to judge supply-side and DSM bids. For example, a utility will usually examine the extent to which a supply-side project can be dispatched, which is generally not applicable to a DSM project. Supply-side and DSM resources also have different project development cycles and costs. For example, supply-side projects are generally more capital-intensive and take longer to construct. This observation has implications for reduced security requirements for DSM projects.

**Utility Incentives for IRP**

Integrated resource planning requires utilities to consider all cost-effective energy resources equally in determining the best way to meet forecasted energy demand. The choice is based on cost; the less costly resources are selected for development before more expensive ones. In this manner, ratepayers and society will be able to meet future demands for energy while minimizing the total resource cost. Implementing IRP in practice in the North America has resulted in increasing utility investments in energy efficiency at the expense of conventional supply-side measures. Such energy efficiency measures include DSM, the use of renewable resources, and switching end-use consumption patterns from one fuel to another.

Despite the strong interest of utility regulators in North America, IRP has had a difficult transition from theory to practice. The major obstacle to its broader application is the traditional regulatory practices of most jurisdictions. Conventional regulation provides powerful disincentives to utility investment in energy efficiency and equally powerful incentives for utilities to increase sales.

Conventional regulation links the earnings of utilities to their level of commodity sales. Because energy efficiency decreases sales, this fundamental orientation of current regulatory practice penalizes energy efficiency investments and is contrary to the intent and goals of IRP. Utility earnings are also adversely affected by regulatory cost-recovery practices. Often these mechanisms produce an implicit bias toward supply-side investments because they sometimes fail to provide full and prompt recovery of utility demand-side resource costs.

Unfortunately, full development of the cost-effective energy efficiency resource will probably not occur without removal of these serious regulatory impediments. Utility executives react to the regulatory and financial environment, and they respond with formidable financial, technical, legal, and political resources. The critical question for government policy makers, lawmakers, regulators and utility executives in Poland is: can proposed regulatory practices be successfully and equitably implemented to create an environment that causes utilities to fully embrace and seriously implement integrated resource planning?

A number of utility incentive mechanisms have been developed and implemented throughout North America in the last ten years to address this question. The development and use of utility incentives depend on the specific goals of regulators and motivations of utilities involved in the process. Therefore, there is no "best" mechanism, which in most cases will probably be a combination of mechanisms. Some utility incentive mechanisms proposed for implementation in Poland are described in Section 3. Following is a brief description of the most common utility incentive mechanisms:

- **Recovery of Resource Costs.** Most participants in the IRP process agree that recovery of resource investment costs is required in order to obtain the enthusiastic support of utility management to aggressively pursue IRP goals. This view holds that utilities should be able to recover all allowable direct costs to design and implement their resource options. For example, these costs include the incentives paid to customers to motivate their participation in DSM programs, payments to vendors to compensate them for implementing resources, and other program-related expenses such as advertising, labor and administration. In most cases the cost recovery is not inherent in the incentive mechanism but is provided through another complementary process for this purpose such as a surcharge or a deferral mechanism.

- **Recovery of Lost Revenues.** A specific problem with DSM is the lost revenue (associated with unavoidable fixed costs) from foregone sales of electricity that customers don't buy because of conservation. Utilities should be able to recover the lost revenue on fixed costs; variable costs (primarily for fuel) are not incurred and are therefore not "lost."

- **Provision of Positive Incentives.** A positive incentive may be required to motivate utility management to overcome the perceived risk of implementing IRP. Regulators increasingly agree that utilities should earn increased profits, at least initially, for successfully accomplishing their goals in IRP by implementing a resource plan with the lowest societal costs and acquiring all cost-effective resources.

## IRP in the Polish Context

The transfer of utility planning concepts from one country to another is challenging because each country has different energy infrastructures, pricing systems, and regulatory institutions. Perhaps nowhere is the challenge more daunting than in Poland that has experienced a wrenching political and economic transition over the past five years.

IRP is principally an American concoction that has relied heavily on government regulation of the utility sector for its implementation. It is also a phenomenon which is relatively new on the scene, and therefore untested in terms of its long-term impacts on the utility industry. For these reasons, some people have criticized the adoption of IRP as a key activity in restructuring the utility sectors of post-communist countries such as Poland. Clearly, a major challenge to the transfer of IRP concepts is to be sensitive to the specific situation in Poland and to adapt the approach accordingly. In this regard, a number of interesting issues confront the implementation of IRP in Poland.

Foremost among these is the fact that in restructuring its electric system, Poland has adopted a variation of the "British model." Five years ago, England and Wales started a radical restructuring of its electric system. From a nationalized, vertically-integrated utility, Britain now has a largely privatized, disaggregated utility system with separate generation, transmission, and distribution companies. This restructuring was undertaken with the primary goal of introducing competition and economic efficiency which would benefit consumers with lower rates.

It is still unclear the extent to which this experiment has succeeded in accomplishing its goal. It has become apparent, however, that the British system provides significant disincentives to the development of DSM as an electric resource, since the distribution companies are motivated to maximize their revenues through increasing retail sales. There are no mechanisms to compensate or reward the distribution companies or any other participant in the system for undertaking DSM. The result is that very little DSM is currently being implemented in the Britain. To the extent that DSM is a least-cost electric resource, this situation poses a real problem for Poland that has adopted a disaggregated utility industry along the lines of the British model. If the problem is not fixed, Poland may not be able to consider a utility planning and resource acquisition process that is optimal from society's point of view.

A fix could be accomplished through adoption of the institutional mechanisms discussed in this **IRP Action Plan** including the use of integrated resource planning in conjunction with a bidding process to acquire electric resources competitively. In that sense, the approach proposed here is really a hybrid between the extremes of Britain's total reliance on market forces and the highly-regulated U.S. model of the power system. As such, this **IRP Action Plan** presents the "Polish model," which is one that takes the best of both worlds to provide a policy framework for utility planning, while allowing the resource acquisition decisions to be made through the competitive forces of the marketplace.

A related issue facing the implementation of IRP in Poland is the current lack of a regulatory framework. In Poland, the nature of the electric utility industry and its relationship to the government is still in a state of flux. Existing decision making structures may not be able to implement the types of changes required by IRP, unless the Energy Law establishes an independent Energy Regulatory Authority (ERA) and subsequent rules promulgated by the ERA allow and encourage IRP.

There are a number of physical characteristics of the Polish power system that are unique and which will require special treatment in any utility planning process. First is the large number of existing power plants that were inherited from the communist era and contribute to significant over-capacity (Poland's current reserve margin is about 35 percent). Many of these plants are quite old and most of them have minimal operating pollution controls. Therefore, the utility planning challenge in Poland is not expansion of the system with new facilities, but the rehabilitation and modernization of the best existing facilities and closure of the worst.

The second interesting characteristic is the large number of combined heat and power (CHP) plants that serve the thermal needs of district heating systems in most of Poland's cities. These plants introduce an operational challenge, since they are generating power and thermal energy continuously during the long winters and thus are "must run" units from the point of view of system dispatch. However, during the summer, most units are operating at very low

levels to provide hot water services or are down for scheduled maintenance. Therefore, it is projected that Poland may face a peak demand problem during the summer months of 1997-1998, when power plants otherwise available are not operating. The interaction between electric and thermal generation and loads poses a difficult utility planning problem that has not been effectively resolved in any other country.

The third interesting characteristic is the nature of Poland's transmission grid. Poland's central geographical position between the great powers has been a curse throughout its history. Its location may finally prove to be a blessing in the twenty-first century. This is because Poland sits in the middle of four major power pools. To the West is the UCPTE system of the European Union, to the East is the huge grid of the former Soviet Union that may become an important market for power someday, to the North are the Scandinavian countries that are creating interties among themselves through a "Baltic Ring" transmission grid, to the South are Poland's natural partners in Hungary and the Czech Republic, and all three nations are now planning coordination of their power systems through the CENTREL grid. The point is that Poland may have a unique opportunity to broker bulk power interchanges between four major trading partners. This fact imposes unique requirements on power system planning. For example, transmission lines and interties gain a strategic importance. Also PPGC owns and operates pumped-storage hydro facilities which must be considered in a resource plan. Finally, joining the UCPTE system, an important goal for Poland, will require meeting the EU's environmental standards for power plants. This requirement will impose a serious constraint on any power system investment plans.

A politically charged issue is the perception that competition will contribute to unemployment in the utility and coal mining industries. Coal mining has been hit hard by the economic transformation in Poland, both as a result of the removal of production subsidies as well as by the fall in demand. The mining workforce has been cut by one-third since 1990 and 22 of 70 mines are slated for closure in the next two years. Poles are asking why utility resource options should be considered that could potentially close down power plants and mines and accelerate unemployment and reduce wages.

Another issue is the uncertainty of industrial facility survival. In the highly unstable economic environment of Poland, a large number of industrial and commercial facilities are being closed, many of them permanently. This situation creates a difficult challenge to the successful investment in any utility resources because of the tremendous uncertainty of load forecasts.

Finally, while the downward spiral of Poland's economy over the last five years is generally considered to be over, a number of problems still remain such as currency instability and uncertainty in business transactions. These problems have generally discouraged aggressive market development and related business activity by international companies that have the capital which Poland needs to rehabilitate and modernize its power sector after forty years of communism. Of course, this problem is not unique to Poland, but is also shared by the other post-communist countries of Eastern and Central Europe and the former Soviet Union. In that context, the development of IRP in Poland could provide a useful model to other countries on how an electric system can be restructured to obtain the benefits of competition through integrated resource planning.

## SECTION 3

## INSTITUTIONAL FRAMEWORK FOR INTEGRATED RESOURCE PLANNING

This section discusses the role of the IRP Unit within the corporate strategy of PPGC and the institutional framework necessary for the IRP Unit to function, including allocation of responsibility within PPGC for each element of the process and the role of outside agencies.

The implementation of IRP in Poland is proposed in a three-phase process that closely tracks the expected transition from the *status quo* to a fully competitive electricity market (see below). This approach is considered necessary because the power sector entities, the generation companies (GENCOS), PPGC as the transmission company, and the distribution companies (DISCOS), each have significantly different roles and responsibilities in each phase. This process provides a gradual transition that would move responsibility for IRP from PPGC to the distribution companies.

The IRP Unit's location and function and the related responsibility for resource acquisition decision-making would be different in each phase as follows:

- Phase 1: The IRP Unit and resource decision-making would be established within PPGC; the IRP plan and contracting strategy are approved by the Ministry of Industry and Trade (MOIT) and subsequently by the Energy Regulatory Authority (ERA) when it is created through the Energy Law; an IRP Review Committee would be established to be composed of PPGC, GENCO and DISCO representatives.

- Phase 2: The IRP Unit would be established as an IRP Independent Organization (INDORG) with a board of directors drawn from PPGC, GENCOS and DISCOS; this step would be taken only when PPGC no longer has the obligation to serve; regulation of the INDORG by ERA is optional or phased out.

- Phase 3: IRP Units would be established at the DISCOS which are responsible for all resource planning and acquisition decisions; ERA would mostly regulate retail prices; the IRP INDORG could continue as an IRP service provider to all power sector entities.

While this section describes IRP activities in all three phases, the remainder of this report focuses solely on IRP activities at PPGC during Phase 1. A more detailed description of the roles and responsibilities of the power sector entities and the function of the IRP Unit in each phase is provided later in this section. Before that, following is a brief description of the three-phase market model for the electricity sector that provides the context for the IRP institutional framework.

**Market Model for the Electricity Sector**

As part of the ongoing process of electricity sector restructuring, PPGC initiated the design of new bulk power trading arrangements, in cooperation with Government, GENCO, and DISCO representatives. The following description of the proposed market model for power trading is a brief summary adapted from the interim report, *Bulk Power Purchase Contracting in a Competitive Market* (March 1994), by Coopers & Lybrand for PPGC.

The key objectives of the proposed trading arrangements for the Polish power sector are:

- To reduce the degree of central control of the sector through the introduction of competitive markets in generation and supply;
- To provide a transition period in which final consumer prices can increase from their current levels to full economic prices;
- To provide transitional financial support to uneconomic generation and distribution companies to enable them to adjust to a more competitive environment; and
- To facilitate the initial phase of private sector investment in the electricity sector.

The proposed trading arrangements would gradually move the power sector toward the longer term goal of operating within a fully competitive market, as follows:

**Phase 1** would nominally last four years, starting in January 1995. During this time, final consumer prices would rise to economic levels, major investments in power plant rehabilitation would take place (including environmental controls), and uneconomic companies would be identified and motivated to cease or change their operations. PPGC would procure most generation capacity through a competitive bidding process that would result in both short-term (1 year) and long-term (10-20 year) contracts. Short-term contracts would play a relatively small role with the emphasis on long-term contracts that would provide the security necessary to finance the rehabilitation and modernization of existing generators. PPGC would sell power to DISCOS through a Bulk Supply Tariff (BST).

**Phase 2** would last for up to ten years, although it could be shortened if circumstances allow. During this time, PPGC would cease signing long-term contracts, and generation would be procured competitively through short-term and medium-term (4-6 year) "contracts for differences" for bulk power sales to PPGC. GENCOS would also compete to be dispatched and any uncontracted capacity would be sold to PPGC at a spot market Pool Price. PPGC would continue to sell to DISCOS at the BST, although large customers could start to buy directly from PPGC at the BST.

**Phase 3** would be the final end-state of the transition process in which trading arrangements would introduce full competition in generation (open access for wholesale wheeling) and the possibility of competition in supply (retail wheeling). PPGC would cease to contract for generation and the BST would cease to exist. GENCOS would contract directly with DISCOS

and large customers through contracts for differences. Uncontracted generation would be sold at the spot market Pool Price. PPGC and the DISCOS would be required to offer access to their networks on a non-discriminatory basis. The extent of competition in supply would depend on the availability and economics of appropriate metering technology and the policies of the Government and the ERA. PPGC's role would be to operate the transmission system, dispatch generation, and provide the Pool Price for pool transactions.

**Location and Function of IRP Units**

The transition in the power sector market model described above has important implications about where the responsibility for resource planning and acquisition is placed. The following proposal defines the roles and responsibilities of the power sector entities by closely tracking the three phases and general relationships described in the market model. However, the proposed approach goes beyond the market model to introduce some new concepts consistent with the goals of IRP (see Section 2). Following is a more detailed description of how IRP would work in each phase:

*Phase 1: IRP Unit is Established within PPGC*

There are a number of reasons for initially developing IRP capabilities at PPGC. The following points provide, in sum, a clear rationale for PPGC taking the lead role in resource planning and acquisition during Phase 1:

- Establishing the IRP Unit within PPGC is consistent with the temporary role that has been delegated to PPGC by MOIT to conduct resource planning for the entire power sector. For example, MOIT's *Energy Policy for Poland and the Draft Programme to the Year 2010* (November 1992) defines PPGC's role as " ... be(ing) responsible for electricity supply security and also for planning and implementation of the main investments of the power sector." PPGC is the only national power sector entity, is owned and governed by the Government through MOIT (which chairs and appoints its Supervisory Board), and as a strategic national asset, will not be wholly privatized but will continue to be majority-owned by the government. Therefore, at least in Phase 1, PPGC has been clearly designated by the Government as the only power sector entity that is in a position to plan and acquire power sector resources. PPGC has articulated specific procedures for this purpose in *The Code of Power System Expansion Planning* (December 1993 draft), which outlines long-term and medium-term national power system planning requirements that are generally consistent with the goals of IRP.

- Establishing the IRP Unit at PPGC is also consistent with its role in being the responsible government entity for receiving power sector loans from the World Bank and other multilateral development banks (MDBs), e.g., the European Bank for Reconstruction and Development. Since the banks require a sovereign guarantee of the loans by the Government, PPGC serves as the only government-owned, national power sector entity capable of participating in the loan appraisal

process, receiving the loans, and distributing the loan proceeds. The requirement in the World Bank transmission sector loan for PPGC to produce this *IRP Action Plan* and implement its results is clear evidence of the World Bank's concurrence with this approach. Also, to the extent that the MDB loans represent a fraction of the total investment program, PPGC also serves as the best organization to coordinate with other sources of debt and equity capital required to implement all appropriate resources.

- Most of the activities that comprise the IRP process are new to Poland, and so it makes sense to concentrate the development of expertise in one organization until the methods are well-known and tested. For example, the various components of the IRP process include integrated resource planning, computer modeling, and competitive bidding, and these are all new activities in Poland. PPGC serves as the critical mass to develop IRP capabilities, especially in light of its existing relations with other power sector organizations and research institutes e.g., Energoprojekt, the Polish Institute for Power Engineering, the Polish Academy of Sciences, and various university departments.

Therefore, the IRP Unit is proposed for establishment within PPGC in Phase 1 (see Exhibit 3-1). The following structure of the IRP Unit and its relationship with other directorates within PPGC explicitly recognize the reorganization through which PPGC is currently undergoing, as described in the *General Plan for the Polish Power Grid Company*, approved by PPGC's Supervisory Board in November 1993.

The IRP Unit would be composed of two functions, each with its own manager that reports to the IRP Unit director. The two functions are:

- Least-Cost Planning (LCP): This function conducts the system load forecasts as well as economic analyses of supply-side, transmission and distribution, and demand-side management (DSM) resources, including environmental considerations; this function then integrates the results of these analyses into an IRP that presents rank-ordered resource options (see Section 4 for a description of these elements of the IRP process).

- Financial and Contract Planning (FCP): This function conducts financial analyses of the highest-ranked resource options resulting from the LCP function, administers a supply-side bidding auction to identify prospects for short-term and long-term contracts, and develops a contracting strategy for the selected resources.

The IRP Unit would coordinate its activities closely with the Market Administration Directorate (also referred to as the "Electricity Turnover" Directorate) which would take the contracting strategy into consideration to negotiate contracts and set tariffs for selected resources. The IRP Unit would also coordinate its activities closely with the Transmission Planning Directorate which would take the rank-ordered resource options into consideration to develop PPGC's transmission system investment program. Both directorates would also be required to provide relevant data

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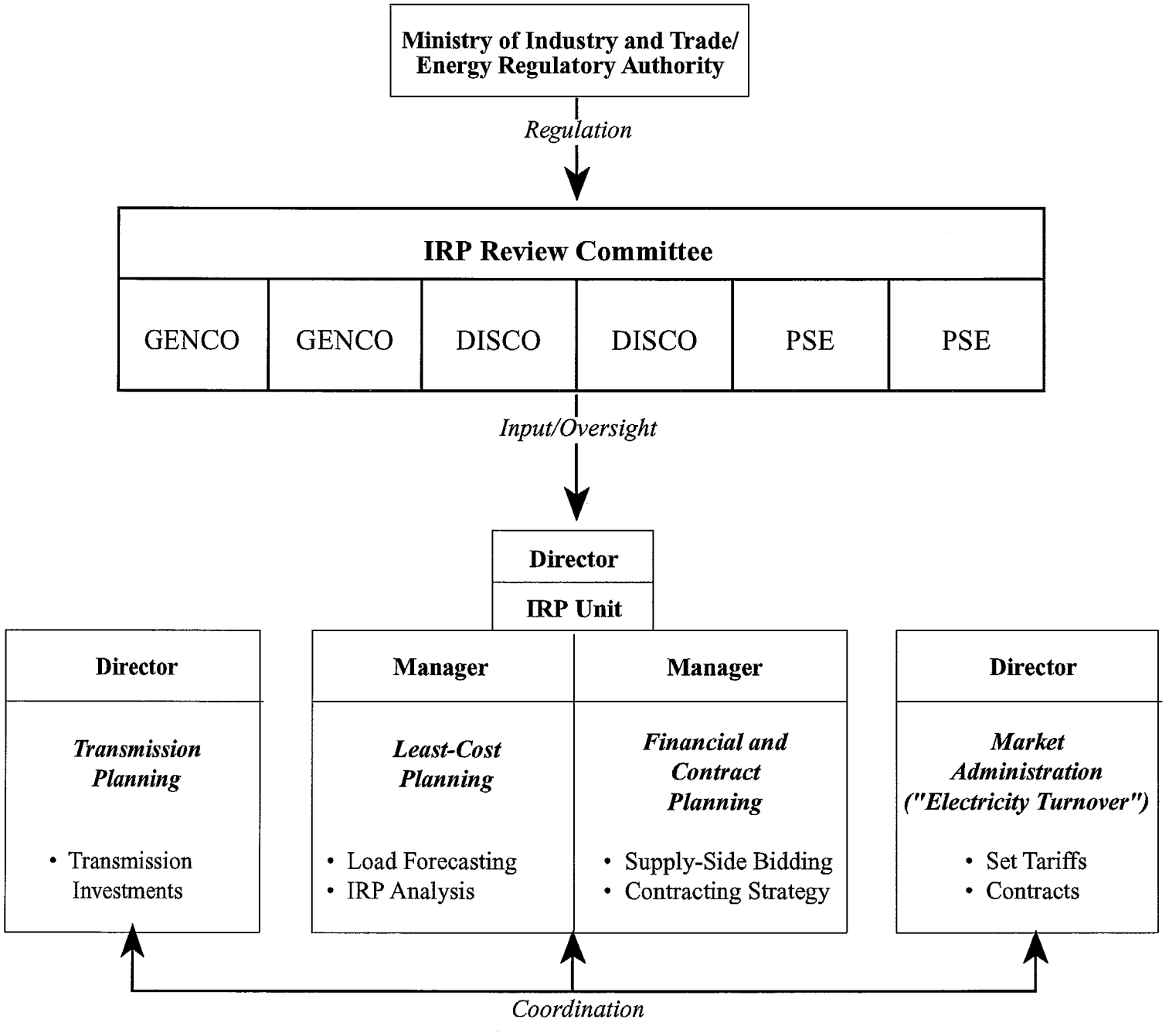
# Phase 1: IRP Unit Is Established within PSE



to the IRP Unit as input to its analyses. These relationships would be formalized in the internal contracts that are being developed between PPGC's operational directorates.

There are three reasons for combining the LCP and FCP functions in one IRP Unit:

- The two functions perform closely inter-related activities that should be coordinated under one director. For example, there will be close iterations between the economic and financial analyses, as well as between the rank-ordering of resources resulting from the IRP analysis and the supply-side bidding process. The development of an effective contracting strategy will require that these two functions work together much more closely than could be achieved if they were in separate directorates.

- Alternatively, both the Market Administration and Transmission Planning Directorates stand apart in their functions. Market Administration deals with PPGC's relationships with the GENCOS and DISCOS and Transmission Planning develops PPGC's own investment program. In both cases, it would be important for the integrity of the IRP process that their activities be conducted independently.

- In Phase 2, the IRP Unit is removed from PPGC and established as an IRP Independent Organization. Clearly establishing the IRP Unit as a discrete entity within PPGC will facilitate its excision, without having to remove sub-programs from other directorates.

While PPGC has been given the near-term lead role in power system resource planning and acquisition, it needs to be sensitive to the legitimate requirements of the GENCOS and DISCOS to participate in the process. Representatives of the Associations of both organizations have been critical of PPGC for taking a dominant position in the process and dictating terms and conditions to the other power sector entities. This concern is especially relevant when considering the proposed evolution of the electricity market in Poland to one in which PPGC becomes another actor in the competitive marketplace. Allowing the GENCOS and DISCOS to participate in the resource planning process will blunt their skepticism that PPGC is self-serving to advance its competitive advantage.

Therefore, it is proposed that an IRP Review Committee be established that is composed of six members: two from PPGC (the IRP Unit director, who would serve as the committee's chairman, and the Market Administration director), two GENCO representatives and two DISCO representatives, who would be nominated by their respective associations. The IRP Review Committee would meet periodically and would agree on data that the various entities would be required to provide PPGC for the IRP analyses (e.g., load forecasts and proposed investment programs). Subcommittees of staff from the entities could be formed into working groups on particular topics. These working groups could include *ad hoc* members from other organizations for special purposes, e.g., large customer representatives could participate in a DSM working group. The IRP Review Committee would also exercise significant oversight of the IRP process and plan and the supply-side bidding procedures and results. Thus, the GENCOS and DISCOS

would be provided a mechanism to participate in the process and "buy-in" to the results. In Phase 2, the role of this committee would be strengthened and formalized as the board of directors of the IRP INDORG.

Demand-side management (DSM) presents a special case during Phase 1. For one thing, DSM is currently an unknown resource in Poland and so it must be demonstrated and its potential must be tested in the real world. To this end, the design and conduct of DSM pilot programs, such as the one currently being implemented in Gliwice, is expected with increasing frequency throughout Phase 1. Such activities will serve to provide a proof-of-concept and will also provide empirical data from the field regarding DSM costs, benefits, and impacts. These data will be essential to refine the results of DSM analyses that are inputs to the IRP planning process.

Another dimension to the implementation of DSM in Phase 1 is the significant disincentives that the DISCOS would face in undertaking any activity like DSM that would reduce their revenues. Such revenue impacts would be especially severe in Phase 1 while retail prices are still rising to economic levels. DISCOS also will not have a mechanism to recover revenue losses on their fixed costs, since the retail tariff will continue to be prescribed by the Government based on "cost-plus" principles in Phase 1. Therefore, some kind of utility incentive mechanism for DSM, to the extent that it is a least-cost resource (as discussed in Section 2), would be appropriate in Phase 1.

The current draft version of the Energy Law (26 May 1994) provides for some type of incentive in Article 50.2 as follows, "Tariffs for energy and fuels may include costs of co-financing by energy enterprises of projects and services which purpose is to reduce energy and fuel use by consumers which provide an economically justified alternative for developing new sources of energy." PPGC should be prepared to negotiate and MOIT/ERA should be prepared to approve such an incentive with DISCOS that can show verified savings from their DSM pilot programs. The exact form of the incentive should be determined in response to a specific request from a DISCO relevant to the implementation of a DSM pilot program. It might be best to consider a "shared savings" type of incentive in which PPGC and the customers participating in the DSM program both pay a share of the cost of DSM, proportionate to the resource savings provided to them by the DSM. For example, PPGC could provide a credit in the BST to the DISCO for its revenue losses on fixed costs and participating customers could repay capital investments in DSM to the DISCO in a fee in their bills. In this scenario, the DISCO would be responsible for covering its own administrative costs of the DSM program.

Regarding the Government's role in Phase 1, MOIT (ERA when it is created through the Energy law and fully operational) would exercise approval authority over the IRP Review Committee's and IRP Unit's activities. MOIT/ERA would approve the IRP plan and the contracting strategy. It could also serve to break tie votes, if necessary, in matters under deliberation by the IRP Review Committee.

*Phase 2: Establishment of IRP Independent Organization*

In Phase 2, the IRP Unit is removed from PPGC and established as an IRP Independent Organization. There are two reasons for this step:

- The purpose of Phase 2 of the market model for the power sector described above, is to provide a transition from a centrally-planned and operated market in Phase 1 to a fully-competitive market in Phase 3. Consistent with this transition process, PPGC will relinquish the obligation to serve early in Phase 2. That is, PPGC will no longer have the responsibility to guarantee the balancing of system supply and load and will no longer bear the risks of that responsibility in its contracts. The moment that PPGC relinquishes the obligation to serve may or may not be precisely defined. For example, it could be at such time that DISCOS start contracting for generation resources directly with GENCOS or it might be when PPGC is making less than a specified percent (e.g., 50 percent) of the country's electric resource decisions through its contracts. For the purposes of this proposal, that moment is defined as when PPGC is no longer signing long-term contracts. At that time, there is no longer any rationale for PPGC to exercise control over the resource planning and acquisition process.

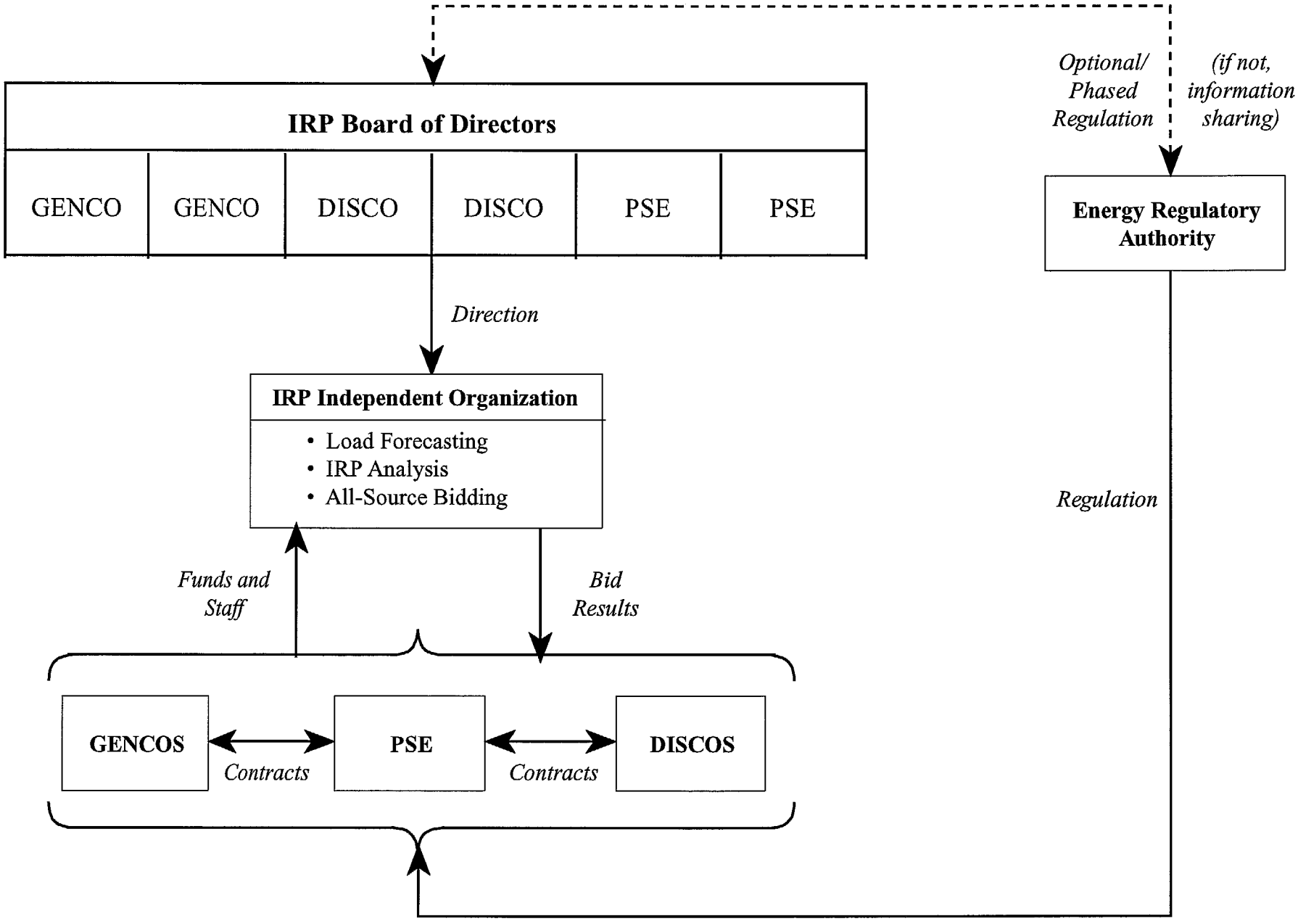
- Consistent with the point above, when PPGC no longer has the obligation to serve, it loses its monopoly status as a buyer of power from GENCOS and a seller of power to DISCOS. At that point, PPGC becomes another competitor in the marketplace. Its Pool Price becomes a benchmark against which GENCOS compare to see if they can receive a better price through transactions with alternative parties, such as DISCOS and large customers. Similarly, the Pool Price becomes the avoided cost against which DISCOS will seek a better deal with GENCOS as well as cogenerators, CHP plants, and independent power producers in their own service territories. Since, PPGC is a competitor in the marketplace, it would face a clear conflict of interest in running the resource planning and acquisition process.

Therefore, an IRP INDORG is proposed that would be created as a private corporation by transferring the IRP Unit from PPGC (see Exhibit 3-2). The INDORG would constitute a fourth power sector entity and would be funded through an assessment on GENCOS, PPGC, and DISCOS, perhaps as a surcharge in the Pool Price. It would also be staffed by all entities and directed by a board of directors that was the IRP Review Committee in Phase 1, with the exception that the chairman of the board would now be elected by the members of the board.

The INDORG would perform two functions as a service organization to all power sector entities. For both functions, use of the INDORG's services would be optional; in all likelihood, each power sector entity will be developing their own IRP expertise during the transition from Phase 1 to Phase 3. Indeed, use of the INDORG's services would facilitate development of IRP expertise, especially at the DISCOS. The two IRP functions are:

Exhibit 3-2

# Phase 2: IRP Unit Is Established as Independent Organization



- Conduct IRP Analyses. The INDORG would continue all of the LCP functions of PPGC's IRP Unit in Phase 1. These functions would include conducting system load forecasts as well as integrating the economic analyses of supply-side, transmission and distribution, and demand-side management (DSM) resources, including environmental considerations. However, the purpose of this exercise is different in Phase 2 since the rank-ordered resource options would serve as proxy resources that would be used to initiate an all-source competitive bidding auction. In effect, the IRP analyses would produce the power sector's "best guess" regarding resource needs and options, from a planning perspective.

- Administer Bidding Process. Using the results of the IRP analyses, the INDORG would then administer an all-source competitive bidding auction. The INDORG would structure the solicitation for bids, establish rules and procedures for running the auction, evaluate proposals received in response to the solicitation, and rank-order bids in accordance with pre-established criteria of the bid rules. In effect, the INDORG would provide a framework for the orderly offering and ranking of resource options from the marketplace. The bidding process would differ significantly from the supply-side bidding of Phase 1, in that all resource options would be eligible to bid, including supply-side, transmission and distribution, and DSM resources (see Section 2 for a general description of the all-source bidding approach). This bidding process could also provide the necessary framework to create a market for trading in pollution emissions, since the offsets associated with particular resources could be included in their bid prices. The specific steps in the bidding process would be as follows:

  -- INDORG would solicit annual bids for power to cover baseload requirements (50 to 60 percent of load).

  -- Eligible bidders for supply-side resources would include the GENCOS, independent power producers, and large electric customers.

  -- Eligible bidders for transmission and distribution resources would include PPGC, the DISCOS, and independent T&D engineering and construction management enterprises.

  -- Eligible bidders for DSM resources would be the DISCOS, energy service companies (ESCOS), and large electric customers.

  -- Bids would include the price offered for the electric resource, the amount of the resource, a deadline to deliver the resource, and security for timely and reliable delivery of the resource.

  -- INDORG would evaluate and rank-order the bids based on price and non-price factors.

-- The power sector entities would then contract for the highest-ranked electric resources and would pay the bid price for those resources over the year.

-- The remainder of load over baseload requirements could then be acquired based on the Pool Price or short-term contracts.

Thus, the bidding results would form the basis for contracts among the GENCOS, PPGC, and the DISCOS. As the market transition evolves through Phase 1, the power sector entities and ERA can evaluate the degree to which the bidding results would be binding in contracts. The argument in favor of binding bidding is that such discipline might be required to prevent the transition into full Phase 3 implementation prematurely. The argument in favor of voluntary bidding is that each power sector entity must retain the independence to act as it wishes, since it is fully bearing the risks of its decisions. Forcing the decision process of an outside organization on them in that circumstance would not be appropriate. A mitigating factor in favor of voluntary bidding is that the independence and integrity of the INDORG and regulatory oversight of the power sector entities by ERA would provide a strong inducement for actions consistent with bidding results. The decision regarding binding versus voluntary bidding can be made in the future, responding to the Government's policies and ERA's regulatory agenda.

In terms of DSM, much of the price disincentives that the DISCOS faced in Phase 1 will have been eliminated in Phase 2, since retail tariffs will have risen to economic levels, and cost-effective DSM should be more attractive to utility customers, without the need for DISCO interventions. Nonetheless, to the extent that the BST in Phase 2 continues to serve as the model for structuring retail tariffs, the DISCOS' may not be able to recover revenue losses on their fixed costs from DSM. A special tariff incentive was proposed in Phase 1 to mitigate this problem, as authorized in the Energy Law. Consistent with the transition to a more competitive market in Phase 2, the special tariff incentive would cease and be replaced by a market-based incentive mechanism.

This observation points to the possibility of the DISCOS bidding DSM resources in Phase 2 for contracts with PPGC. To the extent that those resources are least-cost, the revenue stream from PPGC for DSM acquisition will at least partially, and perhaps wholly, allow the DISCOS to recover their costs and revenue losses from DSM. In this scenario, the DISCOS would turn around and acquire the DSM resources directly from their customers or from energy service companies (ESCOs) acting on behalf of their customers.

DISCOS will be motivated to implement DSM that provides value to them, regardless of the revenue stream from PPGC. Nonetheless, PPGC should be willing to pay for DSM that is competitively bid and that costs less than its avoided generation costs, e.g., in the Pool Price. Therefore, PPGC should be willing to share its savings from DSM with the DISCOS in a credit on the BST. The effect of PPGC buying DSM resources from the DISCOS would be to increase the amount of cost-effective DSM that the DISCOS would otherwise be motivated to implement.

Another option that can be settled in the future is the extent to which the ERA regulates the INDORG's activities. Whether regulation is appropriate or not is a decision that the power sector

entities and ERA should address as the transition to Phase 2 approaches. On the one hand, ERA could regulate the INDORG by approving the IRP plan and the bidding results. In such a case, the regulation could be phased out over time as the switch-over to Phase 3 approaches. If it is decided that ERA should not regulate the INDORG, it would still be appropriate for ERA to formally receive the IRP plan and bid results. It would require these in order to carry out its regulatory requirement of issuing licenses to the power sector entities for their operations based on their contracting activities.

*Phase 3: IRP Established at the DISCOS*

Finally in Phase 3, IRP is decentralized to the DISCOS, consistent with a fully competitive electricity market. When this happens exactly will be unclear, since some "Phase 3-like" activities will probably start happening toward the end of Phase 2, such as open transmission access for wholesale wheeling transactions. In fact, the transition period from Phase 2 to Phase 3 could be greatly accelerated should the Government and power sector entities so choose.

Therefore, all IRP planning and resource acquisition functions would transfer to the DISCOS in Phase 3 which will have assumed the obligation to connect and serve (see Exhibit 3-3). In this role, the DISCOS will conduct their own load forecasting, plan their own resource development and acquisition strategies, and contract for their own resource requirements. In this regard, DISCOS could conduct all-source competitive bidding auctions which would result in contracts with generators and independent power producers for supply-side resources and contracts with ESCOs and customers for DSM resources. The Pool Price from PPGC would represent the DISCOS avoided cost against which all other resources would be compared, and would also be a source of last resort for supply-side resources.

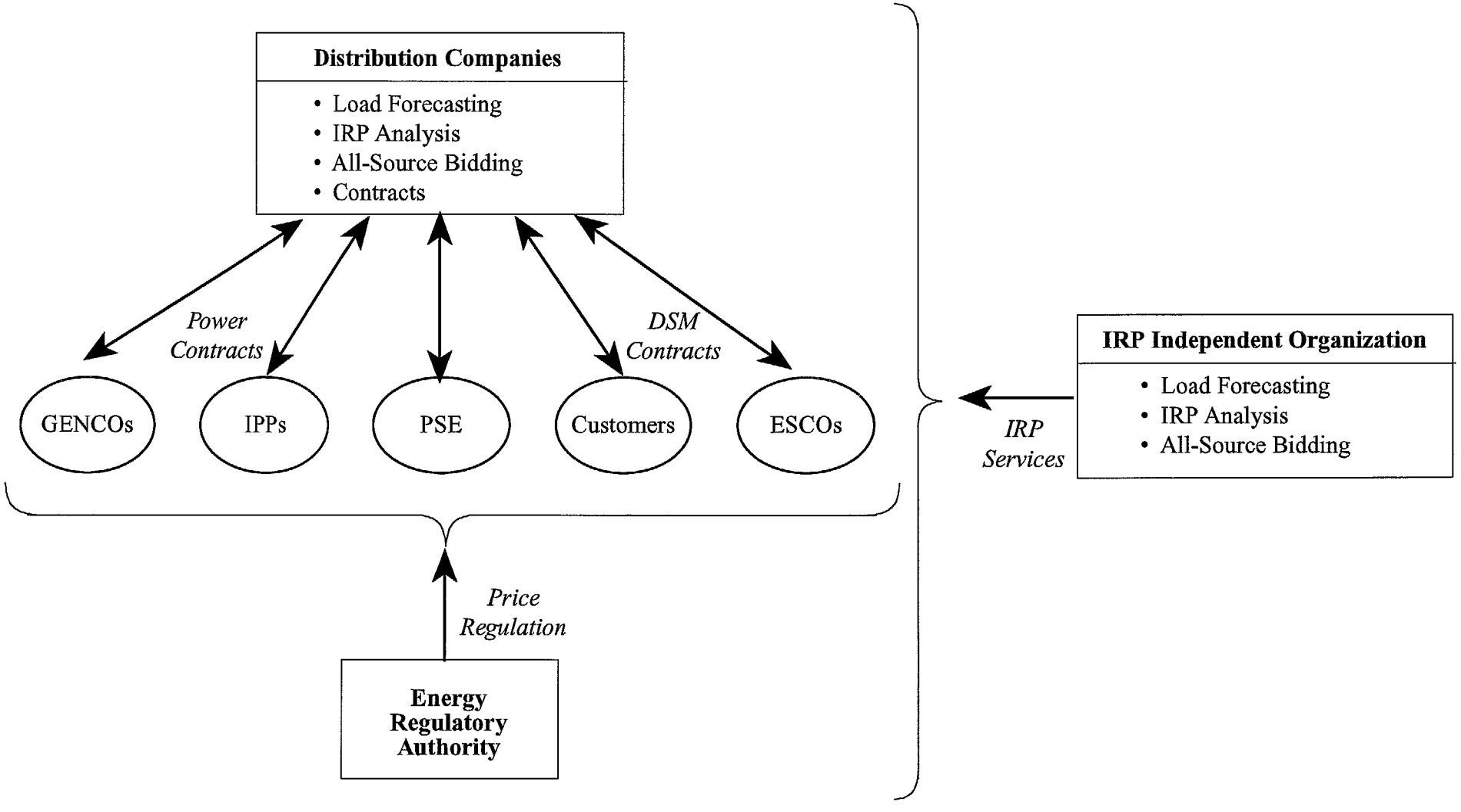
It would be a mistake to assume that the DISCOS would just be starting these activities as the power sector enters Phase 3. They probably will have been conducting their own analyses for years e.g., load forecasting. The difference in Phase 3 is that they would start coordinating all their IRP activities to support their own comprehensive resource planning and acquisition strategies.

The IRP INDORG could be abolished or more likely it could be divested and continue to operate as multiple private fee-for-service utility consulting organizations for all power sector entities, including ERA. Such services would include load forecasting, IRP analyses, and even administering all-source bidding competitions. These services would be particularly appropriate for small DISCOS which might not be able to afford full-scale resource planning and acquisition operations. In this scenario, the INDORGs could retain their original ownership (GENCOS, PPGC, DISCOS) or they could be sold to private and/or government investors.

The situation for DSM in Phase 3 is straight-forward. The BST will cease to exist and DISCOS should be able to recover their fixed costs from all customers in connect charges. Therefore, there should be no more price disincentive for DSM and the utility incentives of Phase 1 or the resource payments from PPGC in Phase 2 will no longer be required. DSM will be able to

Exhibit 3-3

# Phase 3: IRP Units Are Established at the DISCOs



compete like any other least-cost resource in the DISCOS resource planning and acquisition portfolio.

Regarding regulation, the ERA's role in Phase 3 would be fairly limited since there would be greatly reduced monopoly powers in the power system. Nonetheless, ERA would still regulate PPGC's and the DISCOS tariffs and would also oversee the rules of competition.

**Required Actions to Implement IRP Proposal**

There are a number of actions that will need to be taken by the Government and the power sector entities to implement the provisions of this proposal for the establishment of IRP capabilities in Poland. These actions are specific to each phase of implementation as follows:

- Phase 1: After the Energy Law is passed by the Sejm and signed into law, it is likely that subsequent laws will be drafted governing the various energy sectors, i.e., an Electricity Law. It should probably include provisions that enact the market model for the power sector that is ultimately adopted in Poland, not only to anticipate the fundamental changes of its strategic implementation over time, but more importantly to address its near-term operation and the specific relationships between the power sector entities. Most of the general IRP activities, such as PPGC's roles and responsibilities, could be included in such provisions. Following passage of the Electricity Law, ERA would promulgate regulations regarding the IRP process and PPGC would amend the Grid Code to incorporate relevant provisions. A Power Contracting Tendering Code would also have to be developed by PPGC, as anticipated in the market model.

- Phase 2: The main additional requirement will be for a joint venture agreement between the GENCOS, PPGC, and the DISCOS to create the IRP INDORG and to set its rules of operation. ERA would have to determine the extent to which it would regulate the activities of the INDORG and whether the bidding results would be binding upon the power sector entities or not. The Power Contracting Tendering Code would have to be amended to extend the bidding auctions to all-source resources.

- Phase 3: No special legal or regulatory authorities are expected to implement specific IRP provisions in Phase 3, beyond those required to implement the market model.

## SECTION 4

## ELEMENTS OF THE INTEGRATED RESOURCE PLAN

This section identifies and describes the elements of the IRP process. The elements described include:

- load forecasting;
- identification of supply- and demand-side resources;
- transmission system planning;
- environmental considerations;
- plan integration;
- tariff design and power pricing aspects; and
- financial planning.

### Load Forecasting

Load forecasting, the starting point of IRP analysis, is the process of creating forecasts of electricity use and peak demand. Load forecasters use both economic and customer end-use information as input into complex algorithms that forecast both energy and peak electrical use on a total country, distribution company, area, customer class, and load type basis.

The demand forecasters use econometric and end-use techniques to develop the system load projections taking into account the assessment of DSM programs.

#### *End-use Analysis*

End-use analysis produces relationships between the use of electricity for types of electrical use such as heating and the factors that influence that usage. The factors include appliance saturation levels, competitive fuel prices, turnover of the electrical equipment, and improvements in the efficiency of new equipment. The data needed to perform end-use analysis include:

- types of end-use;
- starting load curves, according to characteristic customer load types;
- projected appliance or equipment efficiency standards;
- projection of competitive fuels; and
- appliance saturation rates.

The load forecasters are responsible to estimate the shapes of end-use load curves. These data will also be used in the demand management analysis for determining cost effective DSM measures.

*Econometric Data*

Econometric load forecasting techniques require development of macro-economic forecast assumptions pertaining to the demand projections of electric energy and electric capacity. The historical energy and peak usage is normalized for weather conditions. The resulting normalized loads are then examined by statistical analysis to provide algorithms that relate macro-economic factors to the trend of electric usage. The data to be collected and used in the analysis include:

- Demographics;
- Economic growth;
- Price of electricity;
- Historical electrical energy and peak trends; and
- Long-term information on international sales and purchases.

Transmission losses and unaccounted-for energy such as company electrical use are added into the forecast to show total generation output required.

*Load Forecast Output*

The load forecasts include energy sales and peak load projections for the country, regions, distribution companies, customer classes, and customer load types or end-uses. The various planning models require hourly data as well as load duration data. For example, the Transmission Development Planning Department provides the historical area-related (substations) demands. In turn, the sales forecast should provide a projection on the growth for each substation as input to the transmission planning models.

*Load Forecasting Model*

An effective IRP process requires a suitably efficient load forecasting model to serve as the basis for subsequent resource analyses. PPGC intends to use the Hourly Electric Load Model (HELM) to project the magnitude and shape of load curves in the analyses. This model facilitates the calculations to enable evaluation of numerous variants of future demand for energy. One of the major tasks of the IRP analysis will be to develop the data required for HELM. Given the scarcity of data at this time and the uncertainty as to the pace of economic recovery in Poland, the IRP will include sensitivity analyses on the impact of varying load growth projections.

*Economic Forecasting*

The following information needs to be provided as input to the load forecasting model. An independent group such as from academia that produces regional economic analysis should be asked to provide:

- macro-economic projections;
- sensitivity analysis of macro-economic factors on the projections.

Currently, the Economic Analyses and System Forecast Division of the Development Directorate perform long term forecasting of the national electricity demand, as well as economic efficiency analyses and long term marginal costs projections. PPGC works with various R&D institutes in this forecasting effort. Identification of resources within and outside of PPGC necessary for IRP implementation are described elsewhere in the IRP Action Plan. It is anticipated that the combined use of end-use forecasting, macroeconomic forecasting and sensitivity analyses will provide a sound framework for IRP analyses.

## Identification of Supply and Demand-Side Resources

### *Supply-Side Resources*

The Plan will identify supply-side resources from two perspectives: it will examine existing supply-side resources and screen options for new supply resources. The Plan will first develop a database of the existing supply resources, consisting of the following information:

- generation unit names;
- seasonal generating capacity;
- fuel type;
- age;
- location on the transmission or distribution system;
- mode of operation (base load, peaking, etc.);
- purchases from generation plants or countries; and
- pollution emissions.

With this database, the Plan will evaluate the costs and benefits of several options for existing units, such as the following:

- modernization for environmental and efficiency improvements;
- repowering to increase capacity and efficiency;
- retirement of certain units; and
- alternative fuels to lower cost or pollutants.

To conduct these analyses of existing supply resources, the Plan will compare the costs of each of the alternatives. The annual costs for each option and the alternative will be converted to present value monetary units, then the present values will be accumulated, and these cumulative present values for the option and the alternative will be compared.

The Plan will also evaluate and screen options for new generation. The list of new options to be evaluated will consist of commercially available technologies. These technologies will be grouped into several categories, including:

- base load operation;
- peaking units;
- intermediate operation;
- renewable fuels;
- pumped storage; and
- distributed generation at customer sites.

The technologies will be screened on the basis of a number of factors, including:

- capital cost of the equipment;
- operating cost including maintenance and fuel types;
- expected hours of operation;
- air, water, and solid emissions;
- degree of commercial availability; and
- public acceptance.

The screening process is useful in considering which alternatives should be investigated in greater detail within the IRP process. However, the screening process should not be so severe as to eliminate alternatives that may prove to be beneficial in the final analysis. New options may also include the purchase of power from other countries or from non-utility generation units. Power purchases from outside the grid may require substantial investment in new transmission facilities to connect to a seller of power. The cost of these facilities will be considered in the analysis of new purchases from outside the grid. It is also possible that the seller may share in the cost of the new transmission facilities.

The relative mix of fuel types will be determined by national energy policy goals. The mixture of modes of operation will be determined based on the expected load shape. A mixture of base, intermediate, peaking, and storage units will be needed to efficiently serve electrical load. The results of the screening of new generation options will be used later in the process when a resource plan is developed for the future. The final plan is developed through an iteration process.

PPGC has conducted a number of supply-side analyses that will provide the basic input for IRP analyses. The IRP process will enable PPGC to evaluate these alternatives, as well as DSM programs, on a consistent basis.

*Demand-Side Resources*

PPGC will, in parallel with its assessment of supply options, conduct an assessment of energy-efficiency, load management, and fuel-switching resources. These DSM programs are, in later steps, compared with supply options to develop a portfolio that serves the customers at the lowest cost. A requirement here is that the utility assessment of DSM resources be comparable to and consistent with the assessment of supply resources. The result of demand-side planning will be the identification of the most effective DSM programs for the continued evaluation in the IRP process.

The major steps in the demand planning process are:

- DSM pilot program activities at Distribution companies;
- Defining of the DSM-related objectives;
- Classification of new processes, equipment, etc. to reduce consumption;
- DSM program screening.
- DSM program formulation and cost/benefit analyses; and

The demand resources will be implemented by Distribution companies in close collaboration with the PPGC. PPGC and Distribution companies will work with the Foundation for Energy Efficiency to identify potential DSM programs for implementation by Distribution Companies. Data produced by Distribution companies in pilot DSM programs will be taken into account in this process.

The demand-side planning is an iterative process that uses the feedback from implementation of existing programs. That iterative process includes:

- Identification of target customer sectors;
- Implementation of selected DSM programs;
- Monitoring of program implementation results; and
- Determination of impact on end use load shape.

The primary modelling tool for DSM activities is DSManager. This is a screening program that conducts benefit/cost analysis of DSM programs. It sets bounds for cost-effective DSM resources. Results obtained with the DSManager can be used in calculations carried out in the IRP that identify the optimal solution based on demand and supply options.

**Transmission System Planning**

Transmission system planning efforts focus on providing for a reliable, safe and efficient transmission network, coordinating its efforts with the Distribution Companies and the Network

Operation Branches. The transmission planning function analyzes the system using a load flow program.

Transmission planning uses historical load data for its electrical substations and maintains a database of hourly data. This group also projects future capital projects and operation and maintenance costs of the transmission system.

During the IRP process, Transmission planning cooperates in projects that analyze the reduction of system losses through component replacements and upgrades, reconfiguration of the system, and modifying operating criteria. Work can also include evaluation of placing generation on critically loaded transmission lines.

**Environmental Considerations**

At all phases of the IRP process, the environmental impacts of a decision will be considered. The primary focus of the environmental analysis will be on air emissions including sulfur dioxide, nitrous oxides, particulates, carbon monoxide and carbon dioxide. In addition, where appropriate the following factors will be considered;

- water usage;
- solid wastes produced and disposal needed;
- land usage;
- noise;
- aesthetics and public acceptance; and
- effects of fuel and waste transportation.

When evaluating existing supply resources, the Plan will consider the costs of pollution control equipment and abatement methods which may be needed to meet environmental standards, such as the following:

- scrubbers;
- catalytic converters;
- alternative burners in fossil-fueled plants; and
- alternative fuels; and
- others as appropriate.

When evaluating new and existing generating resources, the costs of pollution control and their expected benefits for specific technologies will be compared to alternative technologies which might have different costs and environmental impacts. The results of this evaluation will have implications for retrofit and retirements of existing units.

**Plan Integration**

After a careful evaluation of supply- and demand-side resources, the Plan will integrate both of these into an integrated resource plan. The Plan will meet the projected needs of the system. The total system needs are the sum of the load forecast and a reserve margin that will provide an accepted reliability. The reserve level should reflect acceptable reliability standards that customers can expect if the utility maintains specified reserves. This reliability standard will balance the needs of the electrical customers against the cost of an increasing level of reliability. Periodically, reserve margins and reliability levels should be reassessed to ensure the appropriate balance.

Integrated planning begins with the declaration of goals and key issues to be addressed in the IRP process. Examples of these issues are rate impacts, emission goals, and overall efficiency improvements.

The most promising supply-side resources, which were analyzed earlier in the process, will be compared to the most promising demand-side resource, which were evaluated in the same way. It is expected that a mixture of supply- and demand-side resources will be needed to meet the long term electricity needs of the grid.

When the Plan integrates supply- and demand-side resources, it must consider many factors. The first factor is cost. The capital and operating costs of generating resources, their fuel usage, expected operation, and the capacity of the resource will be compared to the upfront costs and expected energy savings of demand-side resources. This comparison will also consider the impact of these resources on the price of electricity, both in the near and long term.

Another factor to consider in integrated resource planning is social issues. The Plan will consider national energy goals for fuel usage, cost, employment, reliability, environmental protection, power quality, and integration with other electrical systems in Europe. The Plan will also consider the interactions of the electrical system structure, from the generation providers, to the transmission system, to the distribution, to the final customers.

Since the future is not certain and cannot be predicted, the Plan will also consider different scenarios of key variables. The Plan will assume high and low values for the following variables:

- fuel prices;
- capital equipment costs;
- inflation and interest rates; and
- load growth.

The analysis of different variables will show which choices have risk under certain scenarios. Scenario analysis facilitates improvements to the plan so that it is more flexible and adaptable

to the uncertainties of future conditions. As one or more of the variables change from the values that were used to produce a certain resource plan, then the Plan can be changed to a different set of supply and demand resources that provide lower risk and better opportunity for return under the expected conditions.

**Tariff Design and Power Pricing Aspects**

As electricity rates rise in Poland over time to reflect full economic costs, it will become possible to implement rates that are consistent with the IRP process. There are a variety of rates that are created for the pricing of new resources. These include:

- Interruptible rates;
- Time-of-use rates;
- Long-run avoided energy and capacity rates; and
- Short-run marginal energy rates.

The tariffs are used as an incentive to reduce energy consumption during peak demand periods. The marginal costs of production, distribution, and transmission are key elements in developing marginal-cost based rate tariffs.

Long run marginal costs are used in the evaluation of new resources. The long run marginal costs are used as a benchmark to evaluate new demand-side programs and for capacity to be added to the system. The factors included in the rates include fuel, operation and maintenance costs, depreciation, interest, return on investment, taxes, and insurance on new facilities. These costs can also contain marginal T&D rates depending on the location of a new supply resource on the electrical system.

**Financial Planning**

The IRP process will examine the financial impacts of the resource plan and the financial needs to complete the plan. New capital and internal funds will be used for transmission and other facilities, refurbishment of existing equipment, repowering existing generating units, and installation of pollution control equipment.

Financial planning will examine the pro forma financial condition of the PPGC, beginning with the current financial condition and projecting balance sheets and income statements that would result from the Plan. The financial projection will include cash flows, capital requirements, and will show investors and creditors the expected profitability of the company and its capability to make loan repayment. The planning will also include projections of long term contracts between PPGC and generating companies required to finance plant modernization.

An important part of the Plan is forecasting the average price of electricity. Once a resource plan is selected under Integrated Resource Planning, an estimate of the price of electricity will be made. The price will be used as an input in the load forecast. It may be necessary to pursue several iterations of the resource plan selection, as the electricity price that results from a resource plan may be too high to support economic growth. However, the resource plan needed to maintain a low electricity price may be insufficient to support environmental improvement and economic growth in electricity intensive industries. Therefore, the financial analysis will need to balance the needs of low electricity price against sufficient power sector investment.

The financial plan will develop assumptions that will be used by other planning areas in their analyses. These assumptions include the following:

- interest rates and discount rates;
- fuel costs;
- tax rates; and
- inflation rates in materials and labor.

## Actions to Complete the IRP

PPGC intends to take specific actions to complete the IRP. These actions will involve iterations of some of the forecasting activities to reflect the effects of new forecasts on the IRP. The activities are inter-related with each division dependent of other divisions for data and results. Each of these major activities may involve many small activities.

*Load Forecasting*

1. Compile macro-economic data;
2. Purchase or prepare forecasts of fuel prices (both as a cost of electricity generation and as a substitute for electricity);
3. Compile historical trends in electricity use;
4. Develop end-use load shapes for various customer classes;
5. Develop algorithms that model end uses and economic correlations (price of electricity, growth in economy);
6. Run algorithms to produce forecasts of hourly load data;
7. Use hourly data to determine yearly peak demand;
8. Recalculate price of electricity based on results (resource plan) of load forecast;
9. Recalculate load forecast based on new price of electricity;
10. Using final demand-side expansion, develop final load forecast; and
11. Develop low and high load forecasts to be used in scenario planning.

*Identification of Supply-side Resources*

1. Develop database of generating unit characteristics, fuel costs, power contracts, and load forecast;
2. Develop initial supply database in IRP model;
3. Develop initial marginal costs (see tariff section above);
4. Screen new supply options;
5. Using preliminary load forecast, generation mix, and benefits from transmission interconnections develop system reserve requirements;
6. Develop new capacity expansion to meet system requirements; and
7. Develop short and long term marginal costs from new load forecast and capacity expansion.

*Identification of Demand-side Resources*

1. Determine impact of DSM programs on loads;
2. Determine costs of DSM programs;
3. Determine impact of DSM programs;

4. Forecast impact of future DSM programs;
5. Forecast cost of future DSM programs; and
6. Screen viable future DSM programs.

*Transmission System Planning*

1. Develop historical substation loads database;
2. Develop historical system losses;
3. Develop initial system expansion plan;
4. Produce maps of each region showing existing and proposed transmission lines;
5. Develop estimates of capital and O&M requirements for expansion plan;
6. Develop second iteration of system expansion plan based on new load forecast and new capacity expansion;
7. Analyze the economics of reducing system losses using transmission upgrades; and

*Environmental Considerations*

1. Determine emissions of existing generating units;
2. Determine emissions of future generation additions;
3. Determine impacts on emissions of additions of generating units or DSM programs to resource expansion; and
4. Determine costs of pollution abatement measures (fuel switching, plant retrofits, new technologies).

*Plan Integration*

1. Form IRP review committee;
2. Develop goals and key issues of IRP process;
3. Develop plan for existing and new generating plants;
4. Analyze the costs and benefits of DSM programs; and
5. Use inputs from each area to develop IRP plan using the IPM model.

*Tariff design and power pricing aspects*

1. Develop average cost information using resource plan. Include fuel costs, operation and maintenance, taxes, insurance, depreciation, interest, and return on investment;
2. Calculate marginal energy and capacity cost of serving incremental load over short and long term; and
5. Use marginal and average costs to develop tariffs.

*Financial Planning*

1. Develop financial parameters (interest rates and discount rates);
2. Develop revenue requirements model that includes all costs of providing electricity, such as fuel, operation and maintenance, depreciation, interest, return on investment, transmission and distribution costs;
3. Use revenue requirements model to forecast average price of electricity;
4. Use iteration of load forecast to model new price of electricity;
5. Create annual and five year budgets from revenue requirements model;
6. Project capital requirements to finance budgeted plan; and
7. Analyze most attractive sources of capital.

## SECTION 5

## THE ANALYTICAL FRAMEWORK FOR INTEGRATED RESOURCE PLANNING

This section presents the analytical framework for integrating the elements of the IRP process into a power system development plan, including identifying the flow of information among the elements and specifying the outputs from each element of the process. General concepts of IRP analyses were presented under the heading "IRP Modeling" in Section 3 and each element of the IRP process was identified and described in Section 4. This section builds on that foundation to describe the specific analytical steps of IRP modeling. First, the inputs and outputs of each of the elements are described, including a brief description of PPGC's activities to date in these areas. Then, the process of integrating all the elements into an optimal power sector plan is presented. Finally, PPGC's approach to identifying candidate IRP models and selecting one for use in Poland is described. Exhibit 5-1 presents a flowchart showing all the analytical steps of IRP modeling.

### Inputs and Outputs of IRP Elements

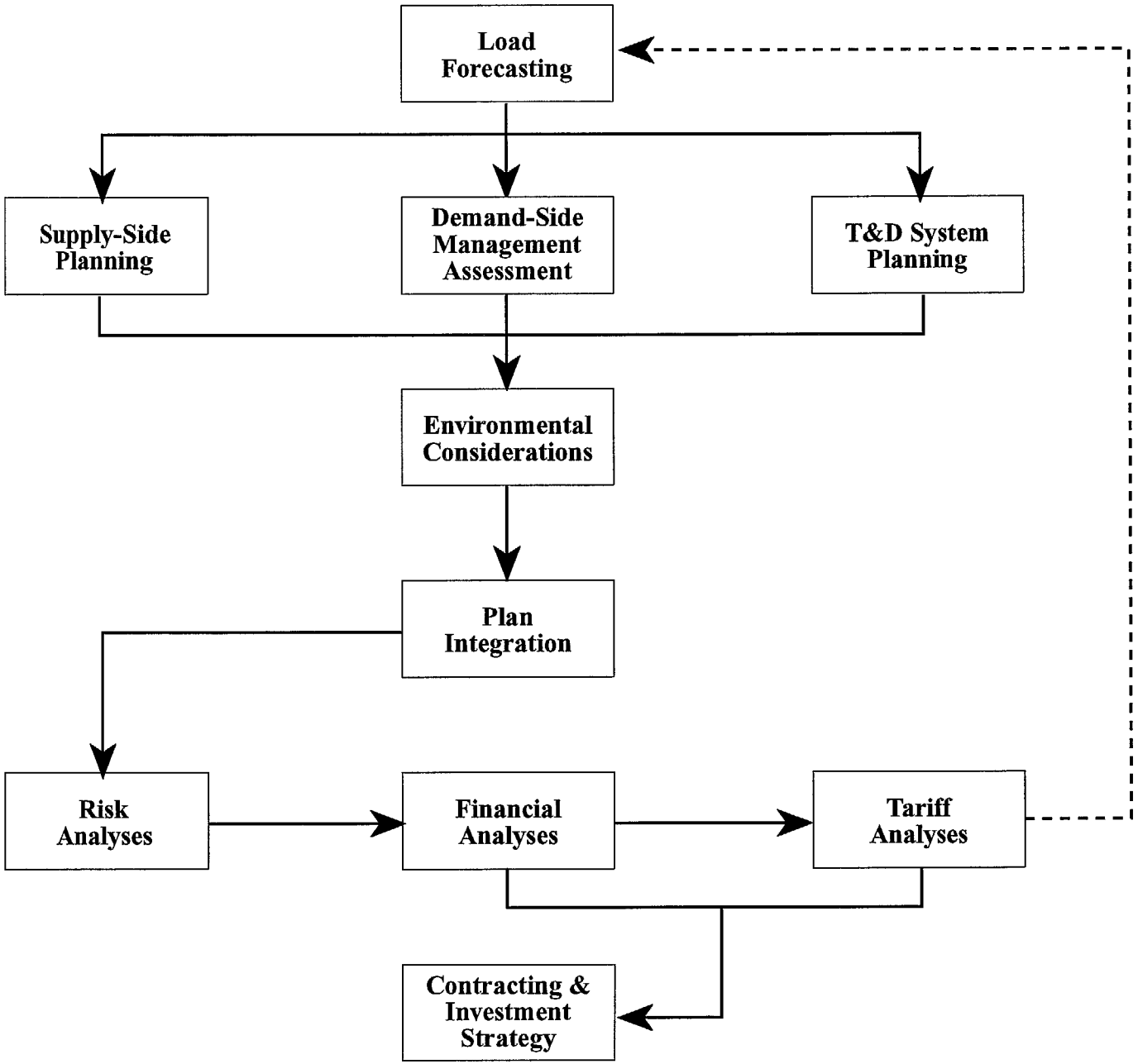
The elements of the IRP process that precede and flow information into plan integration were defined in Section 4 as: load forecasting; the identification of supply-side, demand-side management (DSM) and transmission and distribution (T&D) resources; and the consideration of environmental requirements. Following is a discussion of the analytical processes, data requirements, and results for each element, along with a brief description of PPGC's activities to date in these areas:

**Load Forecasting**. Basic load data required to perform an IRP analysis include historical and forecasted load shape data expressed in terms of hourly megawatts for typical weather years. The accurate representation of hour-by-hour load data has become an expected standard in IRP analyses required for both supply-side and DSM analyses. The load data can be expressed in terms of system, customer class, and end-use loads, as well as system losses at both transmission and distribution levels. Generally, more precise load data are best (e.g., end-use by customer class). In addition to load data, the forecast indicates future peak demands either on a monthly or annual basis with corresponding energy requirements. Forecasts are often described through scenarios (e.g., low, medium, high) reflecting different assumptions about economic activity and government policies.

PPGC has focused much effort on load forecast studies, given the tremendous uncertainty of electric consumption in Poland's post-communist transition. In fact, the uncertainty of this parameter could outweigh all others in the IRP analysis. The studies fall into two categories: 1) macroeconomic forecasts which project future load based on overall indicators of economic activity in the society, e.g., income data, gross domestic product, industrial output, and

Exhibit 5-1

# Analytical Framework for Integrated Resource Planning



population; the Polish Academy of Sciences recently completed such a study; and 2) engineering-based load forecasts that rely more on secondary data regarding customer characteristics and energy consumption patterns; the Polish Institute of Power Engineering has been using the MAED model to conduct biennial load forecasts using this approach. These load forecasts were used in the Long-Run Marginal Cost (LRMC) study that was performed for PPGC by RCG/Hagler, Bailly under a USAID bilateral program, using the Generation Planning Tool (GPT). Future load forecasting efforts could focus on developing hour-by-hour end-use forecasting techniques, using a model such as the Electric Power Research Institute's (EPRI) HELM model.

**Supply-Side Planning**. A supply-side planning study requires detailed data about a utility's load patterns, generating units, operating and maintenance costs (including fuel) and operating characteristics. In addition, specific financial, economic, and planning parameters are required to perform such a study. Most supply-side models use these data to optimize a power sector rehabilitation and expansion plan given certain constraints and objective functions (a discussion of the optimization process is contained under "Plan Integration" below). Data required for supply-side plans can be grouped as follows:

- **Load Data**, derived from load forecasts as described above.

- **Generating Unit Data** which constitute the bulk of the information required for the supply-side analysis, such as:

  -- **Capacity** normally expressed as maximum net dependable capacity for specific units. Generating units are often modeled in capacity blocks or segments and there may be a provision for emergency capacity rating.

  -- **Heat Rates** expressed as the ratio of required fuel to the electrical output of a unit (BTU/kWh). Heat rates vary over the range of a unit's capacity and can vary significantly between units. A heat rate curve is often derived using heat rates at minimum load in conjunction with incremental heat rates.

  -- **Maintenance Schedules** specified as weeks per year that a unit is taken out of service for scheduled maintenance.

  -- **Forced Outage Rates** expressed as a percentage of time that units are expected to be unavailable for service because they break down.

  -- **Energy Limitations** for units that can generate only so much energy at certain times of the year e.g., hydroelectric and pumped storage units.

  -- **Fuel Parameters** associated with the specific fuel type for each unit, such as the heat content, sulfur content, and any limitations on the quantity of fuel available.

-- **Variable Costs** that include fuel costs and variable operations and maintenance (O&M) costs, which are the same costs used in dispatching models to determine how a generating unit is operated.

- **Rehabilitation and Expansion Alternatives** that are candidates for consideration in the supply-side plan. Foe each candidate, data are required on capital, fixed O&M, fuel and variable O&M costs.

- **Economic and Financial Analysis Parameters** such as discount rate, fixed charge rate (e.g., for insurance, depreciation, and tax impacts), cost of debt, common and preferred stock, allowance for funds used during construction and construction work in progress rates, and real escalation rates.

- **Bulk Power Transactions** including firm and economy exchange purchases and sales expected with neighboring electric grids. Data required include the capacity and energy expected from the transactions, with costs of both. Firm transactions could contribute to reserve margin or spinning reserve.

Over the last two years, PPGC has undertaken an extensive supply-side analysis with the assistance of Verbundplan provided through an Austrian bilateral program. The analysis focused on separate plans for new investment and rehabilitation using the WASP model that has been used for years in Poland for utility planning. The new investment plan characterized eight types of generic generating units (e.g., hard coal, lignite, natural gas, pumped storage). The rehabilitation analysis focused on surveys and analyses conducted by ModelPol of the current operational status of existing power plants in Poland.

The Polish power sector poses some unique challenges for supply-side planning that need to be addressed in the future. As discussed in Section 2, the most important issue is that Poland's current needs are not for new construction of generating plants, but for rehabilitation of existing units. With over-capacity of old, dirty power plants, the optimization goal is to identify those plants that would be most economical to rehabilitate, repower, and modernize (including installation of appropriate pollution controls). Another issue is the large amount of combined-heat-and-power (CHP) capacity which must run in the winter, providing an energy contribution, but that cannot be counted on for capacity in the summer. These plants are also subject to rehabilitation and modernization needs. A final issue is the relatively large amount of pumped storage capacity that PPGC owns and operates as part of the transmission system for regulation and providing peak capacity. For each of these issues, specific submodels may be appropriate that explicitly deal with their unique data requirements in a way that WASP or the IRP model cannot. For example, PPGC has used a pumped storage model by Harza and is considering a CHP model by Danish Power Consult. A similar model for rehabilitation analyses should also be identified.

**Demand-Side Management (DSM) Assessment**. A DSM planning study requires detailed data about utility loads, customer preferences, equipment saturations (extent of use), and many factors specifically relevant to customer classes. Data required for DSM analyses include the following:

- **Load Data**, derived from load forecasts as described above.

- **Demographic Characteristics** such as customer information and characteristics, physical characteristics of the building stock, end-use consumption information, and DSM measures already in place.

- **Weather Data** that can be used to normalize system-wide electricity sales and test weather sensitivities to determine the amount of controllable load available through load management DSM programs.

- **Capital Costs** of DSM technologies which will vary with each type of DSM program.

- **Operating Costs** which include the utility's program administrative costs, any financial incentives provided to customers or vendors, and the O&M costs of the DSM technologies.

- **Magnitude and Reliability of Savings** expressed first as the impact of DSM on the utility' load shape and then as total energy and capacity savings potential available from DSM. Analysis of DSM reliability takes into consideration the technical, economic and performance risks of DSM measures and programs. The key performance risk is the persistence of DSM saving over the lifetime of the resource.

- **Market Penetration** which estimates the extent and timing of the implementation of DSM resources, ether through customer preference and choice models or through market diffusion forecasts.

PPGC conducted an assessment of the economic and achievable potential of DSM in Poland in 1992-93 with the assistance of RCG/Hagler Bailly under a USAID bilateral program. The analysis was performed with EPRI's DSManager model that conducts comparative benefit/cost analyses of DSM measures and programs that are used to calculate system impacts of cost-effective DSM. The model is currently being used by the Polish Foundation for Energy Efficiency (FEWE), for example to update the data in the national assessment and to conduct a similar assessment of DSM potential for the Warsaw distribution company.

**Transmission and Distribution (T&D) System Planning**. T&D studies are required in Poland both for analyses of the rehabilitation and reinforcement of the antiquated T&D system as well as for consideration of new T&D facilities. Rehabilitation needs are mostly for substation modernization and sate-of-the-art communications and control capabilities (which will also serve system dispatch requirements). Regarding new facilities, Poland faces a number of opportunities for transmission interties with neighboring grids which could have significant import and export implications for supply-side planning.

T&D models use load-flow programs to model the operation of the T&D system to identify improvements that enhance system efficiency. The capital and operating costs of candidate improvements are then compared with system benefits to identify candidate T&D investments. For example, there are a number of transmission constraints that could be relieved in Poland and there are load centers (especially in the northeast part of the country) that are currently poorly served and for which transmission system investments could be directly compared against supply-side and DSM investments.

PPGC conducted an extensive transmission study in 1992-93 with the assistance of EDF through a French bilateral program. The results were used to appraise the current $225 million World Bank transmission sector loan, which providing roughly 40 percent of the financial resources for required system improvements. PPGC is now considering the PSSE model by Power Technologies to introduce in-house transmission planning capabilities.

**Environmental Considerations**. Compliance with pollution standards is often considered a constraint or policy goal in the system optimization process (see below), however, there are a number of environmental modeling issues that should be addressed before plan integration. The data requirements for environmental analysis fall into three categories:

- **Pollution Emission Profiles** for different types of generation resources which includes cataloging air, water, solid waste, and noise pollution by generator and fuel type and can include modeling the transport and fate of those emissions into the environment. Land-use impacts and aesthetics of generation resources are also often addressed.

- **Pollution Control Costs** for various abatement strategies such as electrostatic precipitators for particulates and scrubbers for sulphur emissions. Alternative fuels, burners, cooling techniques, and waste disposal methods are also considered.

- **Environmental Damage Costs** to the extent that the costs of damage to the environment from residual pollution (externalities) are considered in the resource planning and decision-making process. Both generic and site-specific environmental costs can be modeled.

Poland faces a particularly difficult problem when it comes to environmental considerations. Current electricity generators have limited controls for pollution. While most plants have precipitation for flyash, the units have been poorly maintained and their performance is substandard, in some cases non-existent. There is some sulfur control but none for nitrous oxides. Coal handling and solid waste disposal methods are also rudimentary.

This problem is highlighted by Poland's strong desire to intertie with the UCPTE grid of Western Europe. To do so, European Union (EU) pollution standards must be met. A law was passed by the Sejm requiring power generators to meet that standard by January 1, 1998. This requirement may have more to do with ultimate decisions on power plant rehabilitation and closure than any other factor.

A current dilemma is that the law imposes a standard on each utility boiler, as does the EU standard. However, the most cost-effective pollution control might be determined at the power plant or even regional level. Thus, a particular analytical need that PPGC currently faces is to be able to consider the pollution impacts of "bubbles" that are drawn around ever increasing geographic aggregations of power plants. Such an approach could ultimately lead to an emissions trading market.

PPGC has conducted analyses of pollution emission profiles and pollution control costs for the resource options considered in the Verbundplan supply-side plan. Analysis of residual environmental costs has not been accomplished and a model for that purpose would be necessary, should government policy require consideration of externalities in resource decisions.

**Plan Integration**

All of the modeling and analytical steps described above can be considered "pre-processors" of data that then feed into the IRP analysis. In other words, IRP models provide utility planners with the capability to integrate the results of a number of different models into one systematic analytical framework. Most IRP models will accept the results of any number of other models as inputs. Therefore, PPGC's use of the WASP model or any other model will not be replaced by the IRP model. Instead, PPGC would continue to use the pre-processor models described above in conjunction with the IRP model.

The purpose of IRP models is to produce an optimal mix of available utility assets to determine the type and timing of supply-side, DSM, and T&D resources that best meet the demand forecast requirements over various time periods, taking the environmental issues into consideration. Two different analytical methods have evolved to conduct the resource selection process in a manner which inherently and simultaneously examines all available resource options. This approach is judged to be superior to one involving separate or iterative analyses of supply-side, DSM, and T&D resources (see Section 2 for a more detailed discussion of this distinction).

The first method uses optimization models that incorporate linear or dynamic programming techniques to evaluate all combinations of resource options. From this evaluation, an optimal plan is selected given user-specified reliability constraints and based on an objective function and other policy goals. The second method simulates a utility's chronological performance over long planning horizons and selects the most cost-effective options by ranking all alternatives available each year based predominantly on benefit/cost analyses. Both kinds of IRP models facilitate the analysis of risk due to uncertainty in key assumptions. They also allow financial analyses of resource strategies and enable consideration of the impacts that different resource strategies will have on tariffs. Following is a discussion of the key operational parameters of both approaches.

**Reliability Constraints**. In conducting IRP analyses, certain constraints or planning criteria are specified that all resource options must meet. These usually are defined as reliability criteria that cannot be compromised, no matter what the combination of least-cost resources. Therefore, one of the key aspects of IRP is that an acceptable level of reliability must be maintained. The level

of reliability chosen in Poland will be influenced by PPGC's operational requirements and the Government's preferences. Once a reliability criterion is established, the optimum system plan must ensure that the same level is maintained for all resource alternatives. An equitable comparison of alternatives can only be accomplished if the rule of equal reliability among alternatives is strictly adhered to. Following are the reliability criteria commonly used in IRP models. Some utilities will use only one of these criteria for planning, whereas others will use combinations of these criteria.

- **Reserve Margin** is normally given as a percent and represents the minimum amount of acceptable reserve capacity in excess of the load forecast. The reserve capacity is calculated in any period (usually a year) as the amount of installed capacity minus the peak load divided by the peak load.

- **Loss-of-Load Probability (LOLP)** is an indication of the ability of the generating system to serve all the load requirements in a specified time period i.e., "one day in ten years" means that the utility expects to be able to serve load such that its customers are without service for no more than 24 hours in ten years. LOLP is a function of combinations of forced outage rates of all units and often takes interconnections with neighboring pools into account.

- **Relative Reliability** is a standard index whereby a utility determines the reliability of service in a given year (the benchmark year) against which all other years in the plan are measured.

- **Unserved Energy** places a ceiling on the level of energy that generation units are unable to produce during each year of the planning period, e.g., five or ten percent.

**Objective Functions and Policy Goals**. Given the reliability constraints, IRP models seek a solution which is the optimal combination of least-cost resources by satisfying an objective function which can define "least-cost" in different ways. Most of the optimization models can satisfy one objective function at a time. They can be re-run, however, to meet different objective functions sequentially. Other models (e.g., EPRI's IRP-Manager) can meet multiple objective functions simultaneously. The most common objective functions all minimize "costs" in different ways. These are to minimize: 1) rates; 2) total resource costs; 3) the net present value of revenue requirements; 4) customers' bills (which can be different than #3 in a system with subsidized rates); and 5) resource benefit/cost ratios. These measures differ in the way that "costs" are defined. For example, #2 considers all resource costs, including those of customers e.g., for a DSM resource, while #3 considers only the utility's resource costs.

Some objectives are policy goals which may not be modeled explicitly in an IRP analysis, but are nonetheless tracked. Then, subsequent judgments can be made based on the IRP results regarding the extent to which the least-cost plan also meets the policy goals.

The most common policy goal is whether the optimal plan meets environmental standards (which can also be specified as a constraint). The goal may be to meet an established standard, to minimize pollution levels (that may be below a standard), to minimize environmental externality costs, to minimize pollution taxes, or to maximize the value of offsets in an emissions trading market. Other common policy goals are to maximize fuel diversity, to maximize economic development and job creation (or to minimize job losses), to maximize power quality, and to strengthen interties with neighboring pools.

**Secondary Analyses**. After the optimal least-cost plan is identified that satisfies constraints and meets specified objective functions and policy goals, most IRP models allow a number of secondary analyses. These include analysis of risk due to uncertainty in key variables, analysis of the financial implications of the plan, and analysis of the plan's impact on tariffs. These secondary analyses are described below:

- **Risk Analyses** determine how robust a solution is in the face of an uncertain future (a plan that remains least-cost across widely varying assumptions of the future is robust; a plan that loses its least-cost position when only one or two variables are slightly changed is not robust). There are four common risk analysis techniques used in IRP analyses: 1) Sensitivity analyses alter the input values of key parameters, e.g., fuel prices, capital costs, inflation and interest rates, and load forecasts, to measure the changes in output variables; 2) Decision analyses represent the probability of certain events occurring in the future as forks in a tree; each end-point of the tree represents an independent outcome with a unique solution; 3) Scenario analyses incorporate all of the input variables that create competing scenarios of the future (e.g., an "optimistic" scenario could be defined by a high load forecast, low gas prices, and low inflation rates); and 4) Monte Carlo analyses that develop a cumulative probability distribution representing a range of outcomes that can be expected by changing a single input variable.

- **Financial Analyses** calculate the impact of least-cost resource strategies on the utility's capital requirements, income statement, balance sheet, and source and use of funds. Financial planning examines the *pro forma* financial condition of the utility, beginning with the current financial situation and projecting balance sheets and income statements that would result from the least-cost plan. Financial projections include cash flows, capital requirements, and the expected profitability of the utility and its capability to make loan repayments. Other important aspects of financial analyses include the impacts foreign exchange, import duties, and taxes. The results can be used to develop a contracting strategy required to finance system expansion and rehabilitation.

- **Tariff Analyses** enable consideration of the impacts that different resource strategies will have on the utility's revenue requirements and its customers' electricity tariffs. An important result is a forecast of the average price of electricity. Once a least-cost plan is selected, an estimate of the price of electricity that meets revenue requirements is made which is then fed back to the

load forecast which can change in response to price elasticity assumptions. The long-run marginal cost of the plan is also calculated and fed back to other components of the analysis, e.g., for the determination of cost-effective DSM resources. It may be necessary to pursue several iterations of the resource plan selection process, as the impacts on tariffs of candidate least-cost plans are modeled.

**Development of Contracting/Investment Strategy**. The results of the financial and tariff analyses form the basis for developing a contracting and investment strategy. The resource options which remain highly-ranked after the secondary analyses are identified as candidate projects for financing. These projects would be subject to appraisal under the World Bank's power sector loan and other sources of debt and investment capital. These projects would also be considered by PPGC for contracts with GENCOS. The specific process through which PPGC would use the IRP results to develop a strategy for investments and contracts is discussed in Section 3.

## Selection of IRP Model for PPGC

From October 1993 through March 1994, PPGC systematically evaluated candidate IRP models and selected one for preliminary use in Poland. RCG/Hagler Bailly provided technical assistance and the resources to license the selected model through a USAID bilateral assistance program. Following is a discussion of the model evaluation and selection process, including a description of the selected model.

**Evaluation of Candidate Models**. Nine different state-of-the-art utility planning models that are commonly used for IRP analyses were reviewed. Exhibit 5-2 (at the end of this section) is a table that presents detailed information about these nine models (the exhibit includes a glossary that defines IRP modeling attributes). This comparative analysis of IRP models was taken from *Comparison of Least-Cost Utility Planning Models* (March 1990) by the U.S. Department of Energy. While this information is detailed and comprehensive and believed to be relatively accurate, some of it may be somewhat dated.

A number of criteria were applied to narrow the field to two or three models that could be serious candidates for use by PPGC. These criteria were that the models had to be:

- Fully-documented and tested commercial software products available for license in Poland;
- Able to install on high-end personal computers i.e., 486 machines with comparable clock speed, RAM, and disk storage capabilities.
- Capable of inherently and simultaneously analyzing supply-side, DSM, and T&D resources within a single integrated modeling framework.

- Capable of using data from the models that PPGC has used in related system planning studies e.g., the WASP model used in the supply-side plan, the DSManager model used in the DSM assessment, and the GPT model used in the tariff study.

- Affordable in terms of the budget available through the USAID/Hagler Bailly assistance project which was $25,000 for licensing the model for at least one year, including two weeks of on-site training and technical assistance, and one week of off-site support on the use of the model.

- Capable of providing source code that could be modified in the future to accommodate unique characteristics of the Polish power system.

Two models that met all of the above criteria were identified as candidates for serious evaluation for use in Poland. They were the Electric Power Research Institute's IRP-Manager model (formerly called LMSTM) and ICF Resources' Integrated Planning Model (IPM).

**Model Selection**. The vendors of the two final candidate models were invited to Poland in January 1994 to present their models to a review committee organized and chaired by PPGC staff. The committee included representatives of Energoprojekt and the Polish Institute of Power Engineering who have been previously involved in utility planning studies with PPGC. Each vendor was interviewed over a two-day period which included roughly one day to present the model including computer demonstration, and roughly one day to respond to a list of issues regarding how the models would analyze unique attributes of the Polish power system. Following are brief summaries of the two models:

- **IRP-Manager** was developed by EPRI at a cost of $2 million and has been in use for over ten years by more than fifty utilities in the U.S. It conducts an hourly chronological simulation of system demand and supply for up to 45 years into the future. It can model a number of system attributes of particular interest to Poland including plant rehabilitation, emissions controls, system imports and exports, and private power generation. It uses reserve margin as its reliability constraint and predominantly uses comparative benefit/cost analysis for its objective function, although the user can specify other multiple objective functions (e.g., minimizing total resource costs and rates) that the model can simultaneously solve for. It uses decision trees to conduct risk analyses and provides complete capabilities for financial and tariff analyses.

- **IPM** was originally developed by ICF for the U.S. Environmental Protection Agency at a cost of over $1 million and has been in use for over twelve years by over twenty utilities, states, and power pools in the U.S., Japan, and Europe. It is a dynamic, multi-period, multi-region linear programming optimization model that uses load duration curves to characterize utility supply and demand for up to 70 years into the future. It can model a number of system attributes of particular interest to Poland including sophisticated emissions compliance strategies, pumped

storage, power pool transactions, and a separate characterization of the coal sector. It uses reserve margin as its reliability constraint and net present value of revenue requirements as it objective function. It uses sensitivity analyses for risk assessment and provides complete capabilities for financial and tariff analyses.

Following are the main issues that the vendors were asked to respond to regarding unique attributes of the Polish power system:

- Modeling existing power plants and optimizing a rehabilitation and modernization strategy;
- Meeting the new environmental standards required in 1998 in an optimal fashion;
- Representing combined heat-and-power plants;
- Optimizing peaking capacity which currently is solely provided by pumped storage hydro facilities;
- Introducing natural gas generation technologies;
- Considering options for international exchange of electricity;
- Meeting the standards of the UCPTE grid that are required to join it; and
- Dealing with specific uncertainties faced by Poland e.g., load forecast, availability of foreign investment capital, employment impacts of closing down power plants and coal mines.

Over the course of February and March 1994, the two vendors provided written responses to a number of follow-up inquiries. PPGC's review committee considered all available information and reached consensus to select the IPM model for use in Poland.

The main reason for selecting IPM is that it is a linear programming optimization model similar to the WASP model with which the Polish analysts have much experience. Therefore, it is perceived that the staff effort to prepare data, learn how to use the new model, and interface with the WASP model will be greatly reduced with IPM. The optimization algorithms of IPM are also more proven and familiar to PPGC staff compared to the benefit/cost analysis approach of IRP-Manager which is considered to be novel, unfamiliar, and relatively untested. IPM also handles some of the Polish issues better than IRP-Manager, such as the modeling of pumped storage and gas-fired peaking plants.

**Attributes of IPM**. In addition to the brief discussion of IPM presented above, the following points describe how IPM would be used to model each of the unique aspects of the Polish power system mentioned above:

- **Rehabilitation of Existing Plants**. IPM has the ability to allow creation of up to 50 existing "aggregate unit" reconstruction candidates with three possible upgrade options each that would be unique to that aggregate unit and could include an option to let the unit retire.

- **Meeting New Environmental Standards**. A number of different $SO_2$ and $CO_2$ environmental constraints can be modeled including unit-specific limits, emission rate limits, regional or system-wide limits, and taxes. A number of compliance options can be evaluated such as fuel switching, scrubbers, coal gasification, and natural gas technologies.

- **Modeling CHP Plants**. IPM would model CHP plants in two parts, each as a separate plant. One part is non-dispatchable, follows the heating load, and would have an hourly output pattern by season that is fixed and user-specified. The other part is dispatchable, available over and above the non-dispatchable part, and would look like an ordinary dispatchable plant with its maximum output varying by season.

- **Optimizing Peaking Capacity**. IPM has a detailed representation of pumped storage units for which the user specifies the rate of storage, the storage capacity, and the pumping losses. IPM will determine if and when to use the pumped storage unit and the appropriate storage schedule.

- **Natural Gas Technologies**. IPM contains a complete database of economic and technological aspects of natural gas technologies that would be used in any resource assessment including this option.

- **International Exchange and Meeting UCPTE Standards**. IPM can be used to model a larger region than Poland (in a more aggregate form) in order to capture the market for bulk power transactions between Poland and its neighbors. RED Electrica in Spain has successfully modeled its integration with the UCPTE system with IPM. IPM can evaluate the cost and benefits of meeting the UCPTE pollution and reliability standards.

- **Dealing with Poland's Uncertainties**. IPM's relatively short computational time allows for rapid sensitivity analyses that can be used to compare plans under different assumptions e.g., load growth. IPM can also model fuel constraints such as limits on the availability of particular fuels, e.g., coal contracts. IPM's capability to model the coal sector could be applied to Poland's coal companies. This feature would allow the price of coal to be a function of consumption instead of being an exogenously-supplied forecast.

## CHARACTERISTICS OF LEAST COST PLANNING MODELS

Exhibit 5-2

| Characteristic | | CPAM | EGEAS | ELFIN | IPM | LMSTM3.0 | MIDAS | OGP/FSP | PROSCREEN(2) | UPLAN |
|---|---|---|---|---|---|---|---|---|---|---|
| **Overall** | | | | | | | | | | |
| Study Options | Conservation | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| | Demand-Side | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| | Non-Utility | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| | Supply-Side | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Simultaneous Optimization (DS&SS) | | No | Yes | No | Yes | No | No | No | Yes | No |
| Available | | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Cost | | None | EPRI members | $4,000-$17,000/yr | Client specific | EPRI members | EPRI members | $40,000 | Price by modules | Price by modules |
| **Computer** | | | | | | | | | | |
| Computer Systems | DEC VAX | Possible | Yes | Yes, 1 module | Yes | Yes | No | Yes | Yes | No |
| | Prime | Possible | Yes | Yes | Yes | Yes | No | Yes | Yes | No |
| | IBM Mainframe | Possible | Yes | Yes | Yes | Yes | No | Yes | Yes | No |
| | CDC | Yes | Yes | Yes | No | Yes | No | Yes | No, data general | No |
| | Personal Computers | Yes | Yes, 8 MB required | Yes | Yes | No work stations | Yes - IBM,AT,XT PS/2 | In development | Yes | IBM XT,AT, 3270 AT, PS/2 |
| System Operation Requirements | | 640K,DOS | 3 MB, 8 MB - PC | Standard, 640K | IBM, 512 k | Standard | 640K,8087 M.C. | Standard | Variable | 640K,8087 M.C. |
| Other Model Compatibility | | Yes | Yes | No - Lotus | No | No | No | MAPS | Yes | Yes |
| Processing | | Interactive | Batch, but 7 modules | Batch, but 2 modules | Batch | Batch, but 6 modules | Batch | Batch | Batch or Interactive | Batch or Interactive |
| **Load Shape** | | | | | | | | | | |
| Study Period-Years | | Unlimited | 30 + extsn. period | 100 | Unlimited | 25 | 30 | 30 | Unlimited | 30 |
| Load Data (Form) | | (Peak,min.energy) | Hourly or LDC | Typical weeks | Typical weeks | 16 day types | Typical days | Hourly | Typ. wks. or days | Hourly or LDC |
| Load Data Forecasted | | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Load Data Manipulation | | Periods | 39 prds. possible | Subperiods | Typical days | Typical days | Typical days | Periods | 52 periods | 40 load shapes |
| | Annual | Yes | Yes | Yes | Yes | Yes | Yes (8760) | Yes | Yes | Yes 12 typ. wks. |
| | Monthly | Yes | Yes | Yes | No | No | Yes | Yes | Yes | Yes |
| | Daily | No | Yes | Yes | No | No | Typical days | Yes | Typical days | Yes |
| | Seasonal | Yes | Yes | Yes | 3 only | 4 only | Yes | Yes | Yes | Yes |
| Load Representation | | 8760 hours | 8736 hours COMPASS(1) | 12 typical weeks | 3 seasons | 16 days | 8760 hours | 8760 hours | Typ. or actual wks. | 12 typical weeks |
| **Demand-Side** | | | | | | | | | | |
| Market Penetration Modules | | Exogenous | COMPASS(1) | No | Mkt. poten.input | Market saturation | Yes | Yes | Penetration Rates | Yes |
| Demand-Side Evaluation | Hour-by-Hour | No | Yes | Yes | Yes | Yes | Yes, typical days | Yes | Yes | Yes |
| | Peak Shave | Yes | Yes | Yes | Yes | Yes | Exogenous | Yes | Yes | Yes |
| | Valley Fill | Yes | Yes | Yes | Yes | Yes | Exogenous | Yes | Yes | Yes |
| | Load Shift | No | Yes | Yes | Yes | Yes | Exogenous | Yes | Yes | Yes |
| **Supply-Side** | | | | | | | | | | |
| Fixed Costs | Capital | Yes | Yes | No | Yes | Yes | Yes | Yes | Yes | Yes |
| | Expenses | Yes | Yes | No | Yes | Yes | Yes | Yes | Yes | Yes |
| Variable Costs - Expenses | | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Fuel Escalation | Annual | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| | Monthly | No | No | No | No | No | No | No | Yes | Yes |
| Fuel Limitation | | No | Yes | No | Yes | No | Two fuels/unit | Yes | Yes | No (max lmt. yes) |
| Fuel Types | | Aggregated | Unlimited | Unlimited | Unlimited | Unlimited | Unlimited | 20 | Unlimited | Unlimited |
| Generation Unit | Hydro | Yes | Yes | Yes - 3 only | Yes | 2 types | Yes | Yes | Yes | Yes |
| | Non-dispatchable | Exogenous | Yes | Yes | Yes | No | No | No | Yes | No |
| | Pumped Hydro | Yes, not optimized | Yes - optimizes | Yes, optimizes | Yes | Limited | Yes, limited | Yes | Yes - optimizes | Yes - optimizes |
| | Storage | Exogenous | Yes - optimizes | Yes | Yes | Limited | Yes, limited | Yes | Yes - optimizes | Yes - optimizes |
| | Thermal | Yes | Yes - 5 blocks | Yes | Yes | Yes | Yes | Yes | Yes - 2 inc. rates | Yes - 4 blocks |
| Generation Additions | | Generic units prespecified | All | Generic units prespecified | All but no NDTs | No, optimizes | Yes (BIP) | All but no NDTs | All types | All but no NDTs |
| Production Costing | Probabilistic | No | Yes | Yes | Yes | Monte Carlo | Yes, booth | Yes | Yes | Yes |
| | Deterministic | Yes | Yes (if desired) | Yes (if desired) | Yes | No | Yes, derating | Yes (if desired) | Yes | No |

(1) Demand-side workstation developed by Synergic Resources Corporation.
(2) Characteristics include capabilities of PROSCREEN and PROVIEW models linked together.

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## CHARACTERISTICS OF [illegible]T COST PLANNING MODELS

Exhibit 5-2

| Characteristic | | CPAM | EGEAS | ELFIN | IPM | LMSTM3.0 | MIDAS | OGP/FSP | PROSCREEN(2) | UPLAN |
|---|---|---|---|---|---|---|---|---|---|---|
| **Supply-Side (continued)** | | | | | | | | | | |
| Dispatch | LDC | Yes, exponential | Yes - cumulants | Piecewise linear | Yes | No | Yes | Yes | Yes, cumulants | Yes, MONA |
| | Chronological | No | Chrono.units only | Chrono. units only | No | Yes-16 days | No | No | Chrono.units only | Chrono.units only |
| Operating Constraints | Must Run | No | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes - 2 blocks |
| | Spinning Reserve | No | Yes | Yes | Yes | Yes | No | Yes | Yes | Yes - unit com. |
| | Ramp Rates | No | No | No | No | No | No | No | No | No |
| Forced Outages | Immature | Possible | Yes | No ? | Yes | Annual | Yes | Yes | Yes | Yes |
| | Mature | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| | Partial | No | Yes | Yes | Yes | Yes | No | Yes | Yes | Avg. daily unavail. |
| | Maintenance | Derating | One yr. | Days/years | Yes | Limited | Yes | Yes | Yes | Days per month |
| Purchase Power and Sales | Off-peak | Exogenous | Yes | Can sim. purchase | Yes | Yes-hourly | Yes | Yes | Yes | Yes |
| | Peak | Exogenous | Yes | Can simulate purc | Yes | Yes-hourly | Yes | Yes | Yes | Yes |
| | Scheduled | Exogenous | Yes | Can simulate purc | Yes | Yes-hourly | Yes | Yes | Yes | Yes |
| | Unscheduled | Yes | Yes | No | Yes | Yes-hourly | No | Limited | Yes | Yes |
| Reliability | Reserve Margin | Yes | Yes-optimized | Yes-reported | Yes - optimized | Yes-reported only | Yes | Yes, one only | Yes | Yes-optimized |
| | Loss-of-Load Prob. | No | Yes-optimized | Yes-reported | No | No | No | Yes | Yes | Yes-reported only |
| | Unserved Energy | No | Yes-optimized | No | No | Yes-reported only | Yes, reported | Yes | Yes, reprted only | Yes-reported only |
| Optimization | | No | (Study period or static) | No | (Study period or static) | No | Static, decision tree | heuristic | (Study period or static)(3) | (Static-interactive study period) |
| | Linear | No | Yes | No | Yes | No | No | No | No | No |
| | Non-Linear | No | Yes | No | No | No | No | No | No | Yes |
| | Dynamic Prog. | No | Yes | No | No | No | No | No | Yes | No |
| | Generalized Bndrs. | No | Yes - partial units | No | No | No | No | No | No, heuristic | No |
| **Financial** | | | | | | | | | | |
| Financial Statements | Revenue Rqmt. | Yes | Yes | Yes | Yes(4) | Yes | Yes | Yes | Yes | Yes |
| | Construction | Yes | Yes (STAFF) | Yes | Yes | Yes | No | Yes | Yes | No |
| | Balance Sheet | Yes | Yes (STAFF) | Yes | Yes | Yes | Yes | Yes | Yes (5) | Yes (5) |
| | Income Statement | Yes | Yes (STAFF) | Yes | Yes | Yes | Yes | Yes | Yes (5) | Yes (5) |
| | Sources & Uses | Yes | Yes (STAFF) | Yes | Yes | Yes | Yes | Yes | Yes (5) | Yes (5) |
| Capital Budgeting | | Yes | Yes | No | Yes | No | Yes | Yes | Yes | Yes |
| Financial Optimization | | Feedback | Yes | No | No | No | No | No | No | No, mkt to bk.ratio |
| | Average sys. costs | No | Yes | No | Reported | Yes | No | No | No, in progress | No (target level) |
| | Financial ratios | No | Yes | No | No | Yes | No | No | No | No (target level) |
| Class Revenue Model | | Yes | Yes-exogenous | No ? | No | Yes | Yes | No | Yes | Yes |
| Financial Ratios | | Yes | Yes (STAFF) | Yes, Return on equity, interest coverage | Yes | Yes | Yes | Yes | Yes | Yes |
| **Risk** | | | | | | | | | | |
| Risk Analysis | | Decision tree | Descrbg. function | Possible | Scenario Analysis | No | Decision tree | Possible | Multiple scenario | Yes |
| Value of Information | | No | No | No | No | No | Yes | No | No | No |
| Multi-Objective Analysis | | No | No | No | No | No | Yes | No | No | No |
| **Other** | | | | | | | | | | |
| Marginal Cost | | Possible | Yes-subperiod | Yes | Yes | Yes - hourly | No | Yes | Yes | Yes-hourly |
| Benefit/Cost Ratios | | Yes | COMPASS | No | No | Yes | No | No | No | Yes |
| Multi-area | Economy Interchg. | 3 areas | Yes | Yes | Yes | (6) Yes-hourly | No | Yes | Yes | Betwn. rg.of user spec.1 way only |
| | Reserve Sharing | No | Yes | No | Yes | Yes-hourly | No | Yes | No | Costs |
| Cost-of-Service | | Wholesale level | COMPASS | No | No | Yes | Yes | No | Yes | Lmt.-emb.or marg. |
| Economy Sector | | Exogenous | No | No | Yes | No | No | No | No | No |
| Systems Dynamics | | Yes | Expnsn. plan only | No | No | Rate submod.only | Prices only | No | Prices only | No |
| Price Elasticities | | Possible | COMPASS | No | No | Yes | Yes | No | Yes | No |
| Environmental | | No | Yes | Yes | Yes | Yes | Yes | Yes | No | Emissions rptd. |
| | Optimization | No | No | No | Yes | No | No | No | No | No |

(3) All of the optimization routines are only available when PROVIEW is used in conjunction with PROSCREEN II®
(4) Must be integrated with ICFs Electric Utility Financial Model (EUFM) to provide financial measures.
(5) IOU, municipal and cooperative versions
(6) Has been enhanced by Niagara Mohawk Power Corp.

Exhibit 5-2

## Description of Least Cost Planning Model Characteristics

### OVERALL

Study Options

| | | |
|---|---|---|
| Conservation | - | Programs designed to reduce electric demand at end-use consumption levels. |
| Demand-side | - | Activities related to the design and assessment of utility programs directed at influencing customer use of electricity. |
| Non-utility | - | Independent power producers or cogeneration. |
| Supply-side | - | Determination of generation alternatives to meet customer load. |
| Simultaneous Optimization | - | A "Yes" response indicates that the model is capable of analyzing demand- and supply-side programs simultaneously on an equal basis. A "No" response means that demand-side programs must be analyzed by modifying the load forecast. |
| Available | - | The program is available to anyone requesting the model. |
| Cost | - | Price for EPRI members is $300 for those programs licensed by EPRI. |

### COMPUTER

| | | |
|---|---|---|
| Computer Systems | - | Computer system required by the model. |
| System Operation Req | - | Size and operating system required, if any. |
| Other Model Compatibility | - | A "yes" response indicates that the model is compatible or linked with another model or models. |
| Processing | - | Batch or interactive. |

### LOAD SHAPE

| | | |
|---|---|---|
| Study Period (Years) | - | Maximum number of years the model is capable of handling. |

## LOAD SHAPE (continued)

| | | |
|---|---|---|
| Load Data - (Form) | - | The manipulations in the models are performed on either each hour, a single or several load duration curve(s), or typical days or weeks. This category represents the extent the load data is simplified. |
| Load Data Forecasted | - | If "Yes" the model has the capability to forecast loads according to user specification. |
| Load Data Manipulation | - | The load data can be manipulated on an annual, monthly, daily or seasonal basis. |
| Load Representation | - | The form the load data is represented in the model. |

## DEMAND-SIDE

| | | |
|---|---|---|
| Market Penetration Module | - | The model has the capability to evaluate the market penetration of demand-side programs. |
| Demand-side Evaluation | | |
| Hour-by-Hour | - | The demand-side program impact can be modeled on an hour-by-hour basis for 8,760 hours per year. Both positive and negative changes in load can be analyzed. |
| Peak Shave | - | The model has the ability to analyze demand-side programs that reduce the utility's peak load. |
| Valley Fill | - | The model has the ability to analyze demand-side programs which encompass building loads in the utility's off-peak periods. |
| Load Shift | - | Shifting load from on-peak to off-peak periods. |

## SUPPLY-SIDE

| | | |
|---|---|---|
| Fixed Costs | | |
| Capital | - | The carrying charges for existing and planned generating units or demand-side program. |
| Expenses | - | The fixed operation and maintenance expenses on a dollar-per-kW year basis, which do not vary with kWh produced or sold. |

**SUPPLY-SIDE (continued)**

| | |
|---|---|
| Variable Costs | - The variable operation and maintenance expense for generation units, demand-side programs etc., which vary with the amount of electric energy supplied. |
| Fuel Escalation | |
| Annual | - Fuel escalation rates for each type are entered on an annual basis. |
| Monthly | - Fuel escalation rates for each type are entered on a monthly basis. |
| Fuel Limitation | - Limit on fuel used. |
| Fuel Types | - Fuel types can be represented by unit, by fuel type or aggregated. |
| Generation Unit | |
| Hydro | - Run-of-River Hydro, or any electric generating station in which the prime mover is a turbine or impeller which is driven by water power. |
| Non-Dispatchable | - Resources represented on an hourly basis that may or may not be time dependent. (Examples include wind, solar, demand-side alternatives) |
| Pumped Storage | - A hydroelectric generating station at which electric energy is normally generated during periods of relatively high system demand by utilizing water which has been pumped into a storage reservoir usually during periods of relatively low system demand. |
| Storage | - Pondage hydro, compressed air, etc. |
| Thermal | - Coal, combustion turbines, combined cycle geothermal, nuclear etc. |
| Generation Additions | - In the models optimization routine there are several methods that are used to represent the generation alternatives. Generic units are used to represent various alternatives. "No NDT" means that hourly |

## SUPPLY-SIDE (continued)

| | |
|---|---|
| Generation Additions | generation technologies are not considered in the optimization process, thus the simultaneous evaluation of demand-side programs with supply-side alternatives cannot be accomplished. "BIP" method adds base load, intermediate and peaking units to meet criteria specified. |
| Production Costing | |
| Probabilistic | - The generation capacity probabilistically convoluted based on the forced outage rate specified. |
| Deterministic | - The units are derated by the forced outage rate specified. |
| Dispatch | - The dispatch of the model is based either on a load duration curve or chronological basis. If the model is based on a load duration curve then the method used is specified. The models that list a "yes" for LDC and "chrono units only" under chronological indicate that some technologies can be represented on an hourly basis, then the remainder of the units are dispatched on a LDC basis. |
| Operating Constraints | - The model incorporates must-run, spinning reserve specifications and has the capability to modify the dispatch from an economic bases to non-economic, due to various constraints. |
| Forced Outages | - The forced outage rate gives the fraction of time that a unit is out of service due to mechanical failures. |
| Immature | - If the forced outage rate is different in the early years of a unit's operation yearly variation may be specified. |
| Mature | - The shutting down of a generating unit for emergency reasons. |
| Partial | - The partial shutdown of a generating unit. |
| Maintenance | - The shutdown of a generating unit, for inspection or maintenance, in accordance with an advance schedule. |

## SUPPLY-SIDE (continued)

Purchased Power and Sales

| | |
|---|---|
| Off-peak | - Purchases or sales made during hours with the lowest system load. |
| Peak | - Purchases or sales made during hours with the highest system load. |
| Scheduled | - Sales of unneeded energy from a specific generating unit. |
| Unscheduled | - Purchases or sales spread over a random set of hours. |

Reliability

| | |
|---|---|
| Reserve Margin | - Measures the difference between net system capability and peak load. |
| LOLP | - Measures probability that system demand will exceed capacity during a given period. |
| Unserved Energy | - The energy in a given period that cannot be met with available capacity. |

| | |
|---|---|
| Optimization | - The models can optimize the solution either over the entire study period or on a static basis where each decision is made one year at a time. If the model cannot optimize over the entire study period it is not a proper optimization tool. |
| Linear | - The model optimizes via a linear programming routine. Disadvantage in inaccuracies implicit in the linearity assumption. |
| Non-Linear | - The model optimizes via a nonlinear programming routine. |
| Dynamic Program | - The model is based on a brand and bound algorithm in which all combinations of planning alternatives which satisfy the constraints are evaluated. |
| Generalized Benders | - An iterative process (non-linear and linear) is employed at each step of which a linear problem is solved to obtain a trial expansion plan. |

## FINANCIAL

### Financial Statements

| | | |
|---|---|---|
| Revenue Requirement | - | The sum of estimated O&M expenses, depreciation, taxes and a return on rate base to cover the cost of capital invested. |
| Construction | - | Expenditures for construction including additions, renewals and replacements of utility plant during a specific period. |
| Balance Sheet | - | The presentation of the recorded book amounts of assets, liabilities and invested capital. |

### Financial Statements

| | | |
|---|---|---|
| Income Statement | - | The presentation of the recorded book amounts of all items of income and expense that arise and pertain to all operations for the period reported. |
| Sources and Uses | - | The source and the use of cash, cash flow statement. |

| | | |
|---|---|---|
| Capital Budgeting | - | Budgeting of construction expenditures, and expenditures for the purchase or acquisition of existing utility plant facilities or other investment activities. |
| Financial Optimization | - | The expansion plan results are optimized based on financial parameters specified (¢/kWh, coverage ratios) rather than minimizing revenue requirements. |
| Average System Costs | - | Financial model determines average cents per kWh cost for an optimization plan. |
| Financial Ratios | - | Optimizes expansion plan results based on specific financial ratio. |
| Class Revenue Model | - | Determination of cost responsibility by class. |
| Financial Ratios | - | Reports financial ratios (i.e. coverage ratios) |

## RISK

| | |
|---|---|
| Risk Analysis | - There are several types of risk analysis that can be performed including: decision tree, describing function, scenario analysis, monte carlo or sensitivity analysis. A **decision tree** analysis performs an analysis where chance events are represented by forks in a tree. Each end point of the tree is an independent scenario for which simulations are run. A **describing function** is a process in which key input parameters are varied in the system optimization and production costing assumptions. The describing function fits selected output values to a model containing the varied input values via a transformation and aggregation of the sensitivity variables. **Scenario analysis** is a method which incorporates all of the input variables which create a certain scenario. For example. an "Optimistic Scenario" would include a high load forecast, low gas prices, low inflation rates etc. A **Monte Carlo** analysis is a method which develops a probability distribution by varying a single input variable. The random probability distribution represents a range of outcomes that can be expected. A sensitivity analysis tests on assumption made to an input parameter by altering the input value to measure the changes in the output variables. |
| Value of Information | - Decisions are made before and after certain assumptions are made to determine the value of perfect information. |
| Multi-objective Analysis | - Examines how decisions might change when viewed from the perspective of different objectives. |

## OTHER

| | |
|---|---|
| Marginal Cost | - The change in energy costs associated with a unit change in quantity supplied. |
| Benefit/Cost Ratios | - The benefit and costs are determined for demand-side management programs. |
| Multi-area | |
| Economy Interchange | - KWh delivered to or received by one electric utility system from another. Overall savings may be based on a split-the-savings or percentage profit basis. |

**OTHER (continued)**

| | |
|---|---|
| Reserve Sharing | - One utility can share the reserves of another utility system in order to defer capacity additions. |
| Cost-of-Service | - A study of costs incurred by the utility in producing, transmitting and distributing electricity to its customers, by customer class. |
| Economy Sector | - Evaluates and incorporates economic factors outside of the utility, such as employment, population etc. |
| Systems Dynamics | - Feedback mechanism |
| Price Elasticities | - The ratio of the percentage change in the quantity demanded to the percentage change in price. |
| Environmental | - Considers environmental constraints |
| Optimization | - Expansion plan results are optimized based on environmental constraints. |

## SECTION 6

## RESOURCE NEEDS FOR INTEGRATED RESOURCE PLANNING IMPLEMENTATION

This section identifies the resources within and outside of PPGC necessary for IRP implementation, including (i) staffing requirements, including:

- job descriptions and qualifications;
- subcontracting requirements;
- assessment of PPGC's in-house personnel capacity to undertake IRP-related activities;
- identification of training needs and facilities; and,
- equipment and analytical tools.

### Job Descriptions

Staffing requirements are based on an equivalent fifteen full time individuals involved in the IRP process. In the initial IRP process, this will be comprised of PPGC staff (including new hirings) and outside consultants. Estimated staffing needs to be as follows:

1 - IRP Head
1 - Financial Planning Senior Analyst
1 - Financial Planning Analyst
1 - Demand Planning Senior Analyst
4 - Demand Planning Analysts
1 - Resource Planning Senior Engineer
4 - Resource Planning Engineers
2 - Computer Analysts

Job descriptions for these positions follow.

## Job Description

**Position Title:** IRP Division Head

**Reports to:** Director of Development Management

**Division:** Integrated Resource Planning

---

Position Summary

Employee manages work of senior professionals and is responsible for the preparation of resource planning analyses, assumptions, and recommendations for use in integrated planning functionally reporting to IRP Steering Committee.

Primary Duties

1. Directs the work of senior analysts and engineers.
2. Oversees all integrated resource planning activities.
3. Direct the development and maintenance of various planning models.
4. Review and prepare reports on integrated planning projects.
5. Review the results from the analyses to insure accuracy of work.
6. Coordinates the World Bank loans.
7. Coordinates the work with the generating and distribution companies as it relates to the IRP process.

Typical Requirements

Training and Experience

1. A master's degree in engineering or finance and 10 years utility planning experience, or
2. A baccalaureate degree in engineering or finance and 15 years of utility planning experience, or
3. A related degree and 20 years of utility planning experience.

Knowledge/skill

1. Knowledge of utility planning analysis tools and techniques.
2. Ability to supervise individuals responsible for a diverse planning projects.
3. Ability to effectively work with all levels of management and external contacts.
4. Ability to represent the PPGC before external parties.

## Job Description

**Position Title:** Financial Planning Analyst

**Reports to:** Financial Planning Senior Analyst

**Department:** Economic Evaluation and Planning

**Division:** Integrated Resource Planning

---

Position Summary

Employee conducts financial analysis, develops company-wide assumptions, and contributes to integrated planning process.

Primary Duties

1. Develops financial assumptions for use in all company analyses.
2. Conducts analyses for financing company activities.
3. Develops the forecasted price of electricity.
4. Operates the revenue requirements model.
5. Develops annual and 5 year budgets
6. Analyses potential sources of capital.

Typical Requirements

Training and Experience

1. A baccalaureate degree in finance or economics and 3 years of financial analysis, or
2. A related degree and 7 years of financial analysis.

Knowledge/skill

1. Knowledge of financial analysis tools and techniques.
2. Ability to maintain databases and use financial software packages.
3. Ability to effectively work with all levels of management and external contacts.

## Job Description

**Position Title:** Financial Planning Senior Analyst

**Reports to:** IRP Division Head

**Department:** Economic Evaluation and Planning

**Division:** Integrated Resource Planning

---

Position Summary

Employee manages work of degreed professionals and is responsible for the preparation of financial analyses, assumptions, and recommendations for use in financial planning.

Primary Duties

1. Directs the work of analyst(s).
2. Conducts financial planning activities with other planning departments.
3. Direct the development and maintenance of the revenue requirements model.
4. Review and prepare reports on financing projects.
5. Review the results from the analyses to insure accuracy of work.

Typical Requirements

Training and Experience

1. A master's degree in finance or economics and 5 years experience, or

2. A baccalaureate degree in finance or economics and 8 years of financial analysis, or

3. A related degree and 12 years of financial analysis.

Knowledge/skill

1. Knowledge of financial analysis tools and techniques.

2. Ability to maintain databases and use financial software packages.

3. Ability to effectively work with all levels of management and external contacts.

## Job Description

**Position Title:** Demand Planning Analyst

**Reports to:** Demand Planning Senior Analyst

**Department:** Demand Forecast and DSM

**Division:** Integrated Resource Planning

---

Position Summary

Employee conducts demand planning analysis, develops company-wide assumptions, and contributes to integrated planning process.

Primary Duties

1. Develops long term load forecast and demand-side planning assumptions.
2. Maintains demand planning databases.
3. Operates company's load forecast and demand-side planning models.
4. Analyses the results of various analyses.
5. Prepares draft reports for demand planning department.
6. Coordinates work with other departments and Distribution Companies.
7. Develops demand-side management portion of RFP for new resources.

Typical Requirements

Training and Experience

1. A baccalaureate degree in finance and 3 years of financial analysis, or
2. A related degree and 7 years of economic analysis.

Knowledge/skill

1. Knowledge of forecasting and demand management analysis tools and techniques.
2. Ability to maintain databases and use software packages.
3. Ability to effectively work with all levels of management and external contacts.

## Job Description

**Position Title:** Demand Planning Senior Analyst

**Reports to:** IRP Division Head

**Department:** Demand Planning

**Division:** Integrated Resource Planning

---

Position Summary

Employee manages work of degreed professionals and is responsible for the preparation of demand planning analyses, assumptions, and recommendations for use in demand planning.

Primary Duties

1. Directs the work of analyst(s).
2. Conducts demand planning activities with other planning departments.
3. Direct the development and maintenance of the demand planning models.
4. Review and prepare reports on demand planning projects.
5. Review the results from the analyses to insure accuracy of work.

Typical Requirements

Training and Experience

1. A master's degree in finance or economics and 5 years experience, or

2. A baccalaureate degree in finance and 8 years of economic analysis, or

3. A related degree and 12 years of financial analysis.

Knowledge/skill

1. Knowledge of financial analysis tools and techniques.

2. Ability to maintain databases and use financial software packages.

3. Ability to effectively work with all levels of management and external contacts.

## Job Description

**Position Title:** Resource Planning Engineer

**Reports to:** Resource Planning Senior Engineer

**Department:** Resource Planning

**Division:** Integrated Resource Planning

---

Position Summary

Employee conducts resource planning analysis, develops company-wide assumptions, and contributes to integrated planning process.

Primary Duties

1. Develops long term resource planning assumptions.
2. Maintains resource planning databases.
3. Operates company's integrated planning model.
4. Analyses the results of various analyses.
5. Prepares draft reports for resource planning department.
6. Coordinates work with other departments and generating Companies.
7. Develops supply portion of RFP for new resources.

Typical Requirements

Training and Experience

1. A baccalaureate degree in electrical or mechanical engineering and 3 years of utility production analysis, or

2. A related degree and 7 years of utility production analysis.

Knowledge/skill

1. Knowledge of generation production analysis tools and techniques.

2. Ability to maintain databases and use software packages.

3. Ability to effectively work with all levels of management and external contacts.

## Job Description

**Position Title:** Resource Planning Senior Engineer

**Reports to:** IRP Division Head

**Department:** Resource Planning

**Division:** Integrated Resource Planning

---

Position Summary

Employee manages work of degreed professionals and is responsible for the preparation of resource planning analyses, assumptions, and recommendations for use in resource planning.

Primary Duties

1. Directs the work of analyst(s).
2. Conducts resource planning activities with other planning departments.
3. Direct the development and maintenance of the integrated resource planning models.
4. Review and prepare reports on supply and integrated planning projects.
5. Review the results from the analyses to insure accuracy of work.

Typical Requirements

Training and Experience

1. A master's degree in engineering and 5 years experience, or

2. A baccalaureate degree in engineering and 8 years of engineering analysis, or

3. A related degree and 12 years of engineering analysis.

Knowledge/skill

1. Knowledge of resource planning analysis tools and techniques.

2. Ability to maintain databases and use software packages.

3. Ability to effectively work with all levels of management and external contacts.

## Job Description

**Position Title:** Computer Analyst

**Reports to:** IRP Division Head

**Department:** Technical-Economic Information Center

**Division:** Economic Evaluation and Planning

---

Position Summary

Employees develops software programs and coordinates computer systems development.

Primary Duties

1. Recommend and coordinate computer hardware and software systems.
2. Develop and maintain computer programs.
3. Recommend and install network software.
4. Develop short and long term computer system configurations.
5. Insure computer system security and data backup.

Typical Requirements

Training and Experience

1. A baccalaureate degree in computer engineering and 3 years of computer related work, or

2. A related degree and 7 years of computer related work.

Knowledge/skill

1. Thorough knowledge computer hardware and software.

2. Ability to maintain databases and use software packages.

3. Ability to effectively work with all levels of management and external contacts.

## Subcontracting Requirements

There are two main reasons for subcontracting a substantial portion of the IRP work in the first year, with reliance on outside assistance decreasing in subsequent years. The first reason is to supplement the knowledge of the current staff in performing certain duties. Included this category are:

- Development of the initial load forecast algorithms;
- Identifying viable DSM programs and costs to implement;
- Development of an RFP for resources, if needed; and
- IRP training.

The work to complete the initial IRP will see subcontractors working with or training the PPGC staff on these topics. After the initial IRP cycle, PPGC staff will be responsible to update the initial work performed in the first cycle in future IRP processes.

The other main reason for subcontracting some of the work is that it is costly to maintain a workforce for projects that are either sporadic in nature or highly specialized. Included in this category are:

- Analysis of generating resources such as the cost of equipment upgrades or repowering;
- Development of macro-economic assumptions; and
- Fuels forecast.

The development of macro-economics should not be done in isolation for the PPGC. The results need to be consistent as possible with other industries or competitors in Poland as well as the fuels forecast.

## PPGC Personnel Resources and Training Needs

In order to accomplish a rigorous IRP process, PPGC will need fully trained system planners, financial analysts, supply planners
demand planners, integrated resource planners and computer analysts or programmers. PPGC staff has performed some of these duties in the past. System planners have been investigating system upgrades and load forecasters have been using some of the techniques detailed in item (c). Even so, there will be a need to strengthen everyone's knowledge or skills.

*Training*

Some of the new work will take formal training. The following are the key training programs that are to be completed during the first IRP cycle.

- Engineering economics;
- Training on IPM, HELM and DSManager models;
- Rate design;
- Financial analysis;
- Load forecasting techniques;
- Supply and demand screening techniques;
- RFP development for resource acquisition; and
- DSM analysis.

There will be at least one month of formal training for each staff member involved in the IRP process. Beyond that, the initial IRP process will take longer than future cycles as the staff members learn on the job.

*Personnel Capacity*

The job description for each new position is included elsewhere in the IRP Plan. To the extent that specific skills do not exist in PPGC, personnel with such skills will need to be hired. These personnel will still need to be trained in running the IPM model, on how to coordinate an IRP process, and the development and coordination of a resource RFP. These individuals will be responsible for the identification of supply resources, environmental considerations, and overall integrated resource planning.

The load forecasters will be trained in end-use techniques and demand management planning processes. These individuals will be responsible for load forecasting and identification of demand-side resources.

The computer analyst position requires significant computer training. The personnel to accomplish this work will be hired into the IRP group and provided specific training on the group's packaged software such as DSManager and IPM. These individuals will be responsible for all hardware and software development for the IRP process and provide efficiency improvements in the handling of data and data communications between the different groups involved.

Financial planners will require formal training to incorporate new modeling techniques. They also will need to expand their understanding of financial forecasting and capital requirements of the expanding electrical system.

*Cooperation and Coordination*

The IRP process will require cooperation and team work between individuals, departments, and other companies that have not had to work in such a mode in the past. Also, the IRP process requires the staff members to understand the whole process of resource planning and how their responsibilities impact on others and the final recommendations. These are a key factor and will

be stressed to each staff member. This is another reason the first IRP will take longer than future cycles.

The resource planners are responsible in developing the IRP plan and insuring that the process runs smoothly. When the process does not run smoothly, the resource planners will provide recommendations to the IRP Steering Committee. The Steering Committee will provide guidance to the IRP staff on direction and goals that it deems important and resolve any disagreements that might arise between the individuals involved.

*Facilities*

The facilities required to do this work include computer equipment described in (iv) below. There will be a common area for use as a conference room for IRP meetings, lay-down of materials during the IRP document creation, and a place for computer equipment such as printers and data servers that are not specific to an individual. The desk space required for individuals needs to be able to accommodate a PC and still have adequate working area. A space will be kept for IRP documentation that will include the details of the each process.

*Equipment and Analytical Tools*

The following items will be purchased or leased to maintain databases and accomplish the analyses for the IRP Plan.

Hardware:

PC's for each of the 15 people;
File Server;
Network (and associated software);
Printers; and
Supplies.

Software:

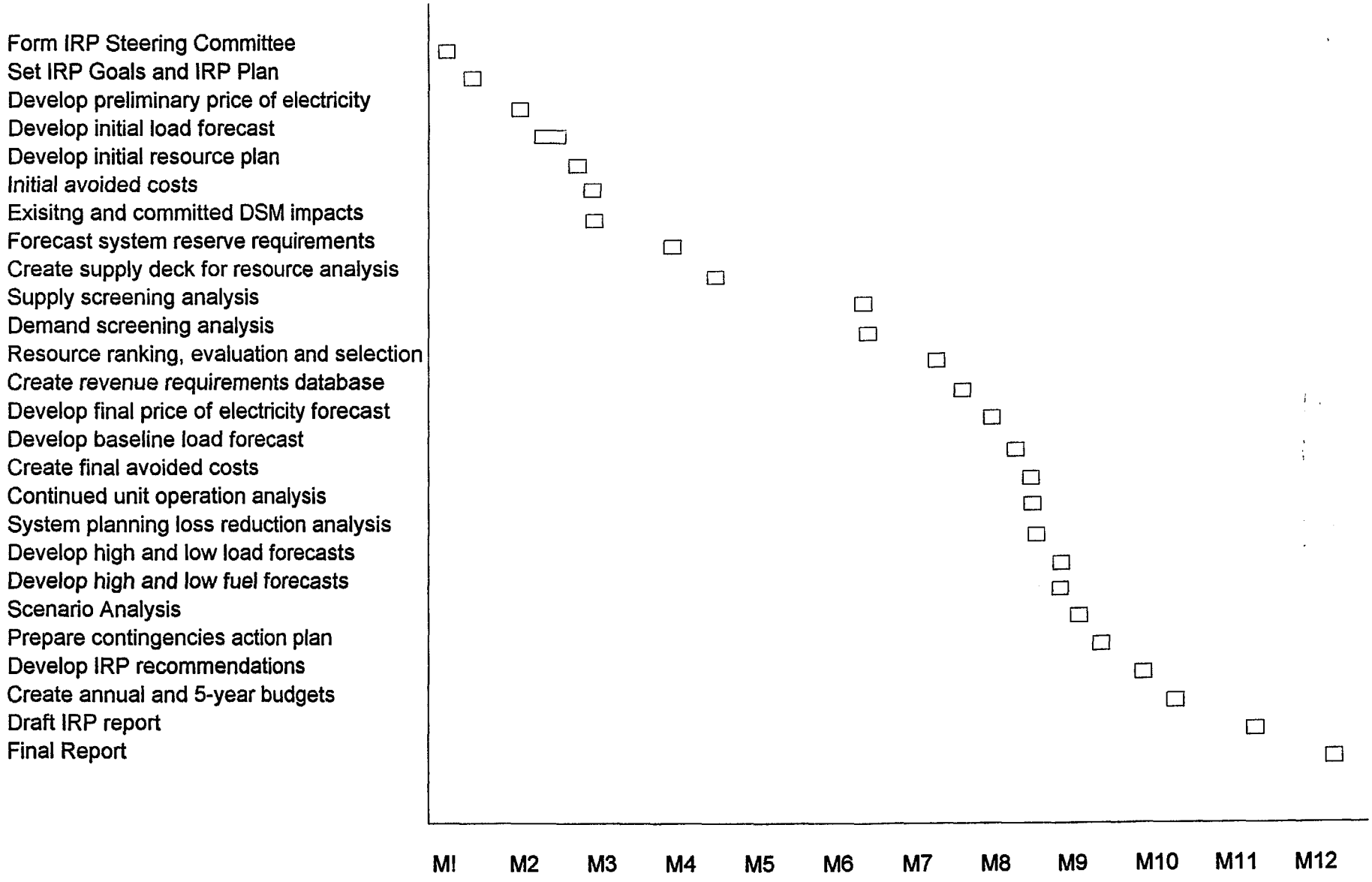
IPM for IRP analysis;
DSManager for DSM program analysis;
HELM for load forecasting;
SAS for statistical analyses;
"C" language;
Word processor such as Microsoft Word;
Spreadsheet such as Microsoft EXCEL;
Graphic software such as Microsoft PowerPoint;
Data server software; and
Network software.

## SECTION 7

## SCHEDULING AND CRITICAL PATH ANALYSIS OF ACTIVITIES

This section describes the approximate scheduling and critical path analysis of activities involved in each element of the process, taking into account the iterative nature of the process. The scheduling and critical path analysis is shown in the following chart. More detailed information including responsible department is included following the chart.

## PPCG IRP Action Plan - Critical path of activities



Integrated Planning Implementation Schedule

| Element No. | Sub No. | Tasks | Department Responsible | Time Frame |
|---|---|---|---|---|
| 1 | | INTEGRATED PLANNING PROCESS | | |
| | 1.1 | Form IRP steering committee | Resource Planning | Month 1 |
| | 1.2 | Develop goals and key issues for IRP | IRP Steering Committee | Month 1 |
| | 1.3 | Develop IRP process plan | Resource Planning | Month 1 |
| | 1.4 | Develop common demand-side programs | Distribution Cos.<br>Demand Planning<br>Resource Planning | Month 8 |
| | 1.5 | Evaluation, ranking, and selection of future resources | Resource Planning | Month 8 |
| | 1.6 | Develop continued operation plan for generating units | Resource Planning<br>Generating Companies<br>Transmission Planning | Month 8 |
| | 1.7 | Environmental analysis | Resource Planning<br>Demand Planning<br>Transmission Planning | Month 8 |
| | 1.8 | Analyze benefits of local or dispersed resources | Resource Planning<br>Demand Planning<br>Transmission Planning | Month 9 |
| | 1.9 | Analyze scenarios and develop contingencies | Resource Planning<br>Financial Planning | Month 10 |
| | 1.10 | Develop IRP recommendations | IRP Steering Committee | Month 10 |
| | 1.11 | Prepare IRP report | Resource Planning | Month 11 |

Integrated Planning Implementation Schedule

| Element No. | Sub No. | Tasks | Department Responsible | Time Frame |
|---|---|---|---|---|
| 2. | | LOAD FORECAST DEVELOPMENT | | |
| | 2.1 | Develop preliminary load forecast | Demand Planning | Month 2 |
| | 2.2 | Macro-economic data | Outside Consultant | Month 2 |
| | 2.3 | End-use load shapes | Distribution Cos.<br>Demand Planning | Month 3 |
| | 2.4 | Fuel Forecasts | Outside Consultant | Month 2 |
| | 2.5 | Historical trends | Transmission Planning | Month 2 |
| | 2.6 | Develop Algorithms | Demand Planning | Month 4 |
| | 2.7 | Produce hourly load data | Demand Planning | Month 6 |
| | 2.8 | Develop low and high load forecasts | Demand Planning | Month 8 |

Integrated Planning Implementation Schedule

| Element No. | Sub No. | Tasks | Department Responsible | Time Frame |
|---|---|---|---|---|
| 3 | | DEMAND MANAGEMENT | | |
| | 3.1 | Existing DSM programs impacts | Distribution Cos.<br>Demand Planning | Month 2 |
| | 3.2 | Existing DSM programs costs | Distribution Cos. | Month 2 |
| | 3.3 | Committed DSM program impacts | Demand Planning | Month 3 |
| | 3.4 | Committed DSM programs costs | Demand Planning | Month 3 |
| | 3.5 | Viable future DSM programs impacts and costs | Demand Planning and Outside consultant | Month 5 |
| | 3.6 | Screening of future viable DSM programs | Demand Planning | Month 7 |

Integrated Planning Implementation Schedule

| Element No. | Sub No. | Tasks | Department Responsible | Time Frame |
|---|---|---|---|---|
| 4 | | SUPPLY PLANNING | | |
| | 4.1 | Develop generating unit characteristic data | Resource Planning | Month 2 |
| | 4.2 | Develop initial supply database (IPM model) | Resource Planning | Month 3 |
| | 4.3 | Develop initial marginal costs | Resource Planning | Month 3 |
| | 4.4 | Screen new supply options | Resource Planning | Month 4 |
| | 4.5 | System reserve requirements | Resource Planning | Month 5 |
| | 4.6 | Develop capacity expansion | Resource Planning | Month 8 |
| | 4.7 | Develop short and long term marginal costs | Resource Planning | Month 10 |

Integrated Planning Implementation Schedule

| Element No. | Sub No. | Tasks | Department Responsible | Time Frame |
|---|---|---|---|---|
| 5 | | FINANCIAL PLANNING | | |
| | 5.1 | Preliminary price of electricity | Financial Planning | Month 2 |
| | 5.2 | Forecast financial escalators | Financial Planning | Month 3 |
| | 5.3 | Develop revenue requirements model | Financial Planning | Month 6 |
| | 5.4 | Develop price of electricity forecast | Financial Planning | Month 8 |
| | 5.5 | Create annual and 5 year budgets and business plan | Financial Planning | Month 8 |
| | 5.6 | Projection of capital requirements | Financial Planning | Month 8 |
| | 5.7 | Analyze sources of capital | Financial Planning | Month 7 |

Integrated Planning Implementation Schedule

| Element No. | Sub No. | Tasks | Department Responsible | Time Frame |
|---|---|---|---|---|
| 6 | | TRANSMISSION PLANNING | | |
| | 6.1 | Develop historical substation loads | Transmission Planning | Month 1 |
| | 6.2 | Develop historical system losses | Transmission Planning | Month 2 |
| | 6.3 | Develop initial system expansion plan | Transmission Planning | Month 5 |
| | 6.4 | Produce maps of each region showing existing and proposed transmission lines | Planning Transmission | Month 8 |
| | 6.5 | Develop capital and O&M estimates | Transmission Planning | Month 8 |
| | 6.6 | Analyze transmission upgrade to reduce system losses | Transmission Planning | Month 9 |

## SECTION 8

## BUDGET FOR IMPLEMENTATION OF INTEGRATED RESOURCE PLANNING

This section presents estimated budgets for the implementation of the IRP process. The budget described in this section is based on a four year program during phase 1 of the market transition model. The budgets for the IRP-related work do not include PPGC personnel and administration costs, office space, computing facilities nor translation expenses. The budget assumes that PPGC will make such facilities and services available for its own personnel and outside contractors.

The budget is presented for the various elements of the IRP action plan.

# IRP IMPLEMENTATION BUDGET (1994 U.S. $X1000)

| | YR 1 | YR 2 | YR 3 | YR 4 | YEARS 1-4 |
|---|---|---|---|---|---|
| **Load Forecasting** | | | | | |
| HELM Model Maintenance | $20 | $20 | $20 | $20 | $80 |
| Technical Institutes | 50 | 50 | 50 | 50 | 200 |
| T/A macroeconomic forecast | 50 | 50 | 50 | 50 | 200 |
| T/A end use forecast | 200 | 100 | 100 | 100 | 500 |
| Training | 50 | 30 | 30 | 30 | 140 |
| Subtotal | 370 | 250 | 250 | 250 | 1120 |
| **Supply and Demand-Side Resource Identification** | | | | | |
| Technical Institutes/FEWE | 100 | 50 | 50 | 50 | 250 |
| Technical assistance | 200 | 50 | 50 | 50 | 350 |
| WASP model maintenance | 20 | 20 | 20 | 20 | 80 |
| Training | 30 | 20 | 20 | 20 | 90 |
| DSManager | 20 | 20 | 20 | 20 | 80 |
| Subtotal | 370 | 160 | 160 | 160 | 850 |
| **Transmission Planning** | | | | | |
| Technical Assistance | 30 | 0 | 0 | 0 | 30 |
| PSSE Model | 400 | 20 | 20 | 20 | 460 |
| Training | 20 | 20 | 20 | 20 | 80 |
| Subtotal | 450 | 40 | 40 | 40 | 570 |
| **Environmental Considerations** | | | | | |
| Technical Institutes | 50 | 50 | 50 | 50 | 200 |
| Technical Assistance | 150 | 50 | 50 | 50 | 300 |
| Training | 50 | 50 | 50 | 50 | 200 |
| Subtotal | 250 | 150 | 150 | 150 | 700 |
| **Plan Integration** | | | | | |
| Technical Institutes | 100 | 50 | 50 | 50 | 250 |
| IPM Model | 50 | 50 | 50 | 50 | 200 |
| Technical Assistance | 150 | 100 | 50 | 50 | 350 |
| Subtotal | 300 | 200 | 150 | 150 | 800 |
| **Tariff Designs and Pricing** | | | | | |
| Technical Assistance | 50 | 50 | 50 | 50 | 200 |
| Training | 40 | 20 | 20 | 20 | 100 |
| Subtotal | 90 | 70 | 70 | 70 | 300 |
| **Financial Planning** | | | | | |
| Technical Assistance | 100 | 50 | 50 | 50 | 250 |
| **Contingency** | 200 | 100 | 100 | 100 | 500 |
| Total | 2130 | 1020 | 970 | 970 | 5090 |

**INTEGRATED RESOURCE PLAN BUDGET SUMMARY**
**(1994 U.S. $X1000)**

| | YR 1 | YR 2 | YR 3 | YR 4 | YEARS 1-4 |
|---|---|---|---|---|---|
| Load Forecasting | 370 | 250 | 250 | 250 | 1120 |
| Supply and Demand-side | 370 | 160 | 160 | 160 | 850 |
| Transmission Planning | 450 | 40 | 40 | 40 | 570 |
| Environmental Considerations | 250 | 150 | 150 | 150 | 700 |
| Plan Integration | 300 | 200 | 150 | 150 | 800 |
| Tariff Design, Pricing | 90 | 70 | 70 | 70 | 300 |
| Financial Planning | 100 | 50 | 50 | 50 | 250 |
| Contingency | 200 | 100 | 100 | 100 | 500 |
| Total | 2130 | 1020 | 970 | 970 | 5090 |

# PROPOSAL TO ESTABLISH INTEGRATED RESOURCE PLANNING CAPABILITIES IN POLAND

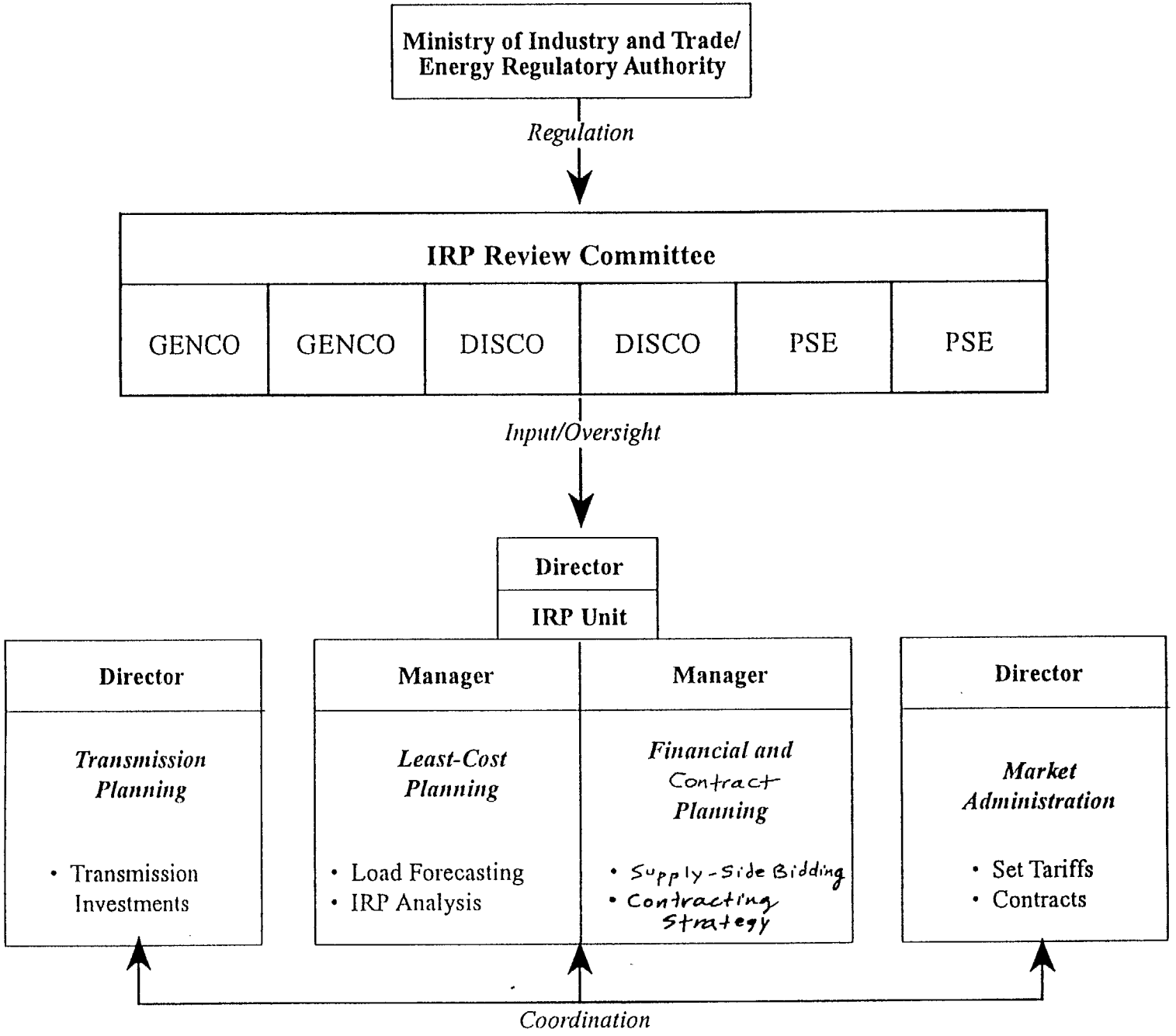
- THREE-PHASE PROCESS THAT CLOSELY TRACKS THE PROPOSED TRANSITION FROM THE STATUS QUO TO A FULLY COMPETITIVE ELECTRICITY MARKET
  - POWER SECTOR ENTITIES HAVE SIGNIFICANTLY DIFFERENT ROLES AND RESPONSIBILITIES IN EACH PHASE
  - TRANSITION PROVIDES GRADUAL PROCESS TO MOVE RESPONSIBILITY FOR IRP FROM PSE TO THE DISTRIBUTION COMPANIES
- IRP UNIT LOCATION/FUNCTION AND RESOURCE ACQUISITION DECISION-MAKING IS DIFFERENT IN EACH PHASE:
  - PHASE 1: IRP UNIT AND RESOURCE DECISION-MAKING IS ESTABLISHED WITHIN PSE; PLANS ARE APPROVED BY MOIT/ERA; REVIEW COMMITTEE INCLUDES PSE, GENCO AND DISCO REPRESENTATIVES, CHAIRED BY PSE
  - PHASE 2: IRP UNIT IS ESTABLISHED AS AN INDEPENDENT ORGANIZATION WITH A BOARD OF DIRECTORS DRAWN FROM PSE, GENCOS AND DISCOS (EACH ENTITY MAKES RESOURCE DECISIONS); REGULATION OF THE INDEPENDENT ORGANIZATION BY ERA IS OPTIONAL OR PHASED OUT
  - PHASE 3: IRP UNITS ARE ESTABLISHED AT THE DISCOS; INDEPENDENT ORGANIZATION COULD CONTINUE AS IRP SERVICE PROVIDER TO ALL POWER SECTOR ENTITIES

# PROPOSAL TO ESTABLISH INTEGRATED RESOURCE PLANNING CAPABILITIES IN POLAND

## PHASE 1

- IRP UNIT IS ESTABLISHED WITHIN PSE, COMPOSED OF TWO FUNCTIONS, EACH WITH ITS OWN MANAGER THAT REPORTS TO A DIRECTOR. TWO FUNCTIONS ARE:
  - LEAST-COST PLANNING (LCP): CONDUCTS LOAD FORECAST AND ECONOMIC ANALYSES OF SUPPLY, T&D AND DSM RESOURCES; DEVELOPS RANK-ORDERED RESOURCES THROUGH INTEGRATED RESOURCE PLANNING
  - FINANCIAL AND CONTRACT PLANNING: CONDUCTS FINANCIAL ANALYSES, ADMINISTERS SUPPLY-SIDE BIDDING AUCTION, AND DEVELOPS CONTRACTING STRATEGY FOR SELECTED RESOURCES
- IRP UNIT COORDINATES WITH MARKET ADMINISTRATION DIRECTORATE (WHICH SETS TARIFFS AND NEGOTIATES CONTRACTS FOR SELECTED RESOURCES) AND TRANSMISSION PLANNING DIRECTORATE (WHICH DEVELOPS PSE'S TRANSMISSION INVESTMENT PROGRAM)
- IRP REVIEW COMMITTEE IS COMPOSED OF SIX MEMBERS: PSE'S IRP DIRECTOR (CHAIR) AND MARKET ADMINISTRATION DIRECTOR, TWO GENCO REPRESENTATIVES, TWO DISCO REPRESENTATIVES; COMMITTEE PROVIDES DATA AND OVERSEES IRP PROCESS AND RESULTS
- MOIT (ERA WHEN IT EXISTS) APPROVES IRP PROCESS AND RESULTS

# Phase 1: IRP Unit Is Established within PSE

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PROPOSAL TO ESTABLISH INTEGRATED RESOURCE PLANNING CAPABILITIES IN POLAND

PHASE 2

- WHEN PSE NO LONGER HAS THE OBLIGATION TO SERVE (E.G., STOPS SIGNING LONG-TERM CONTRACTS), IRP UNIT TRANSFERS OUTSIDE OF PSE TO BECOME INDEPENDENT ORGANIZATION FUNDED, STAFFED, AND DIRECTED BY PSE, GENCOS & DISCOS (CHAIR IS ELECTED BY THE BOARD)
- IRP INDEPENDENT ORGANIZATION PERFORMS TWO FUNCTIONS:
  - CONDUCTS IRP ANALYSIS TO IDENTIFY PROXY RESOURCES TO START ALL-SOURCE COMPETITIVE BIDDING AUCTION
  - ADMINISTERS COMPETITIVE BIDDING FOR SUPPLY, T&D, AND DSM RESOURCES, RESULTING IN MARKET-BASED RANK-ORDERING
- IT IS OPTIONAL WHETHER BIDDING RESULTS ARE BINDING OR WHETHER THEY ARE SIMPLY TAKEN INTO CONSIDERATION IN CONTRACTS AMONG PSE, GENCOS, AND DISCOS
- ERA MAY REGULATE THE IRP METHODOLOGY AND PLAN, BIDDING PROCESS AND RESULTS; IF SO, REGULATION MAY BE PHASED OUT OVER TIME; IF NOT, ERA WILL RECEIVE THE PLAN AND BID RESULTS; OTHERWISE, ERA ISSUES LICENSES BASED ON CONTRACTS

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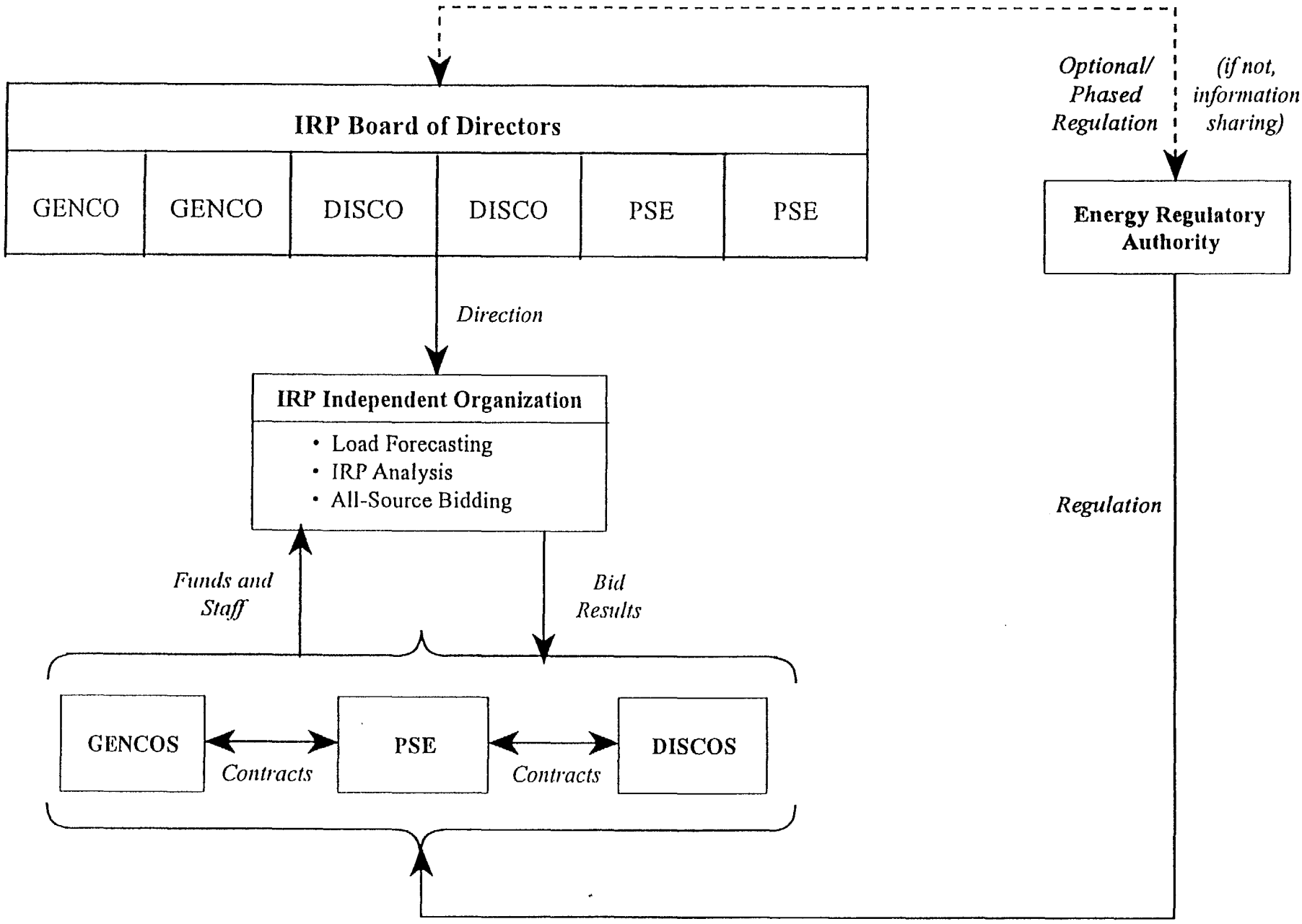
# Phase 2: IRP Unit Is Established as Independent Organization

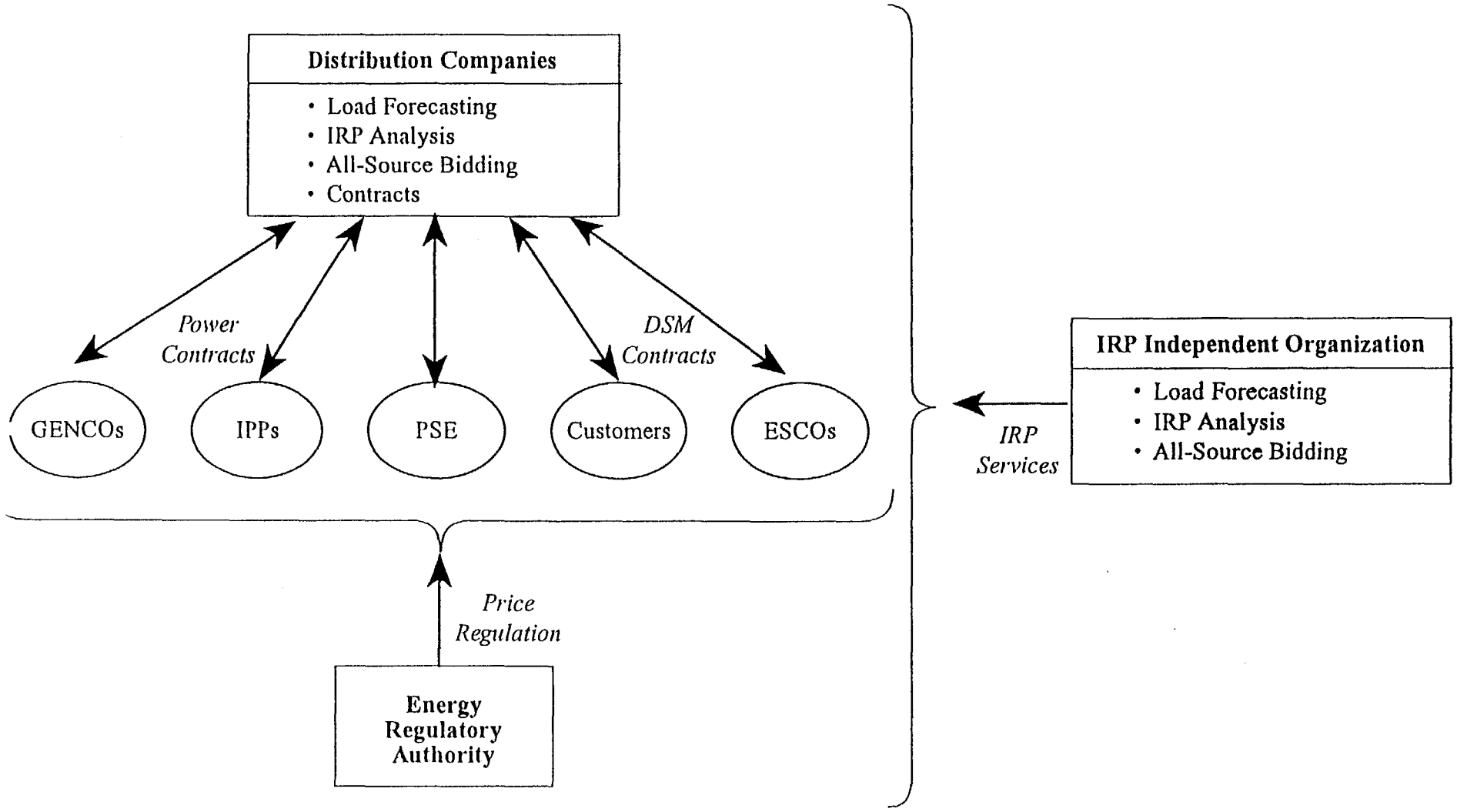


PROPOSAL TO ESTABLISH INTEGRATED RESOURCE PLANNING CAPABILITIES IN POLAND

PHASE 3

- ALL IRP PLANNING AND RESOURCE ACQUISITION FUNCTIONS TRANSFER TO THE DISCOS WHICH HAVE THE OBLIGATION TO CONNECT AND SERVE AND THEREFORE:
  - CONDUCT THEIR OWN LOAD FORECASTING
  - PLAN THEIR OWN RESOURCE DEVELOPMENT AND ACQUISITION STRATEGIES
  - CONTRACT WITH GENERATORS AND CUSTOMERS FOR SUPPLY AND DSM RESOURCES
- IRP INDEPENDENT ORGANIZATION COULD CONTINUE TO OPERATE AS PRIVATE FEE-FOR-SERVICE UTILITY PLANNING ORGANIZATION FOR ALL POWER SECTOR ENTITIES; COULD RETAIN ORIGINAL OWNERSHIP OR BE SOLD
- ENERGY REGULATORY AUTHORITY REGULATES PSE AND DISCO TARIFFS, AND RULES OF COMPETITION

# Phase 3: IRP Units Are Established at the DISCOs



## SUMMARY OF ATTRIBUTES

- INITIAL PERIOD (PHASE 1) ALLOWS RESOURCE PLANNING AND DECISION-MAKING WITHIN PSE
  - CONSISTENT WITH TEMPORARY ROLE DELEGATED TO PSE BY MOIT TO CONDUCT RESOURCE PLANNING FOR ENTIRE POWER SECTOR
  - CONSISTENT WITH LEAD ROLE IN WORLD BANK LOAN APPRAISAL
- HOWEVER, GENCOS AND DISCOS PLAY SIGNIFICANT OVERSIGHT ROLE, PROVIDE DATA TO PLANNING PROCESS (E.G., FOR LOAD FORECASTS), AND "BUY-IN" TO RESULTS
- MOVE TO INDEPENDENT ORGANIZATION IN PHASE 2 IS CONSISTENT WITH MARKET TRANSITION TO FULL COMPETITION IN PHASE 3
  - TRANSITION PERIOD COULD BE EASED INTO OR ACCELERATED
  - ENTITIES MAY RETAIN INDEPENDENCE TO CONTRACT AS THEY WISH
  - IF SO, INTEGRITY OF INDEPENDENT ORGANIZATION AND REGULATORY OVERSIGHT OF ENTITIES PROVIDE STRONG INDUCEMENT FOR ACTIONS CONSISTENT WITH BIDDING RESULTS
- IN PHASE 3, IRP IS DECENTRALIZED TO THE DISCOS, CONSISTENT WITH A FULLY COMPETITIVE ELECTRICITY MARKET

# CENTRAL AND EASTERN EUROPE
# REGIONAL ENERGY EFFICIENCY PROJECT
# EUR-0030-C-00-2053-00

**Energy Pricing, Energy Efficiency, and**
**Energy Sector Restructuring Component**

**Poland**
**Private Power Pricing**

*Task Completion Memorandum*

*Prepared for:*

U.S. Agency for International Development
Bureau for Europe and NIS
Office of Environment, Energy,
and Urban Development
Energy and Infrastructure Division

*Prepared by:*

Hagler Bailly Consulting, Inc.
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October 1996

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# CENTRAL AND EASTERN EUROPE
# REGIONAL ENERGY EFFICIENCY PROJECT

*Task Completion Memorandum*

## *Poland - Private Power Pricing*

### Summary Task Description

The task will include several activities in support of the Polish Power grid Company (PPGC) to build upon work already begun in electricity tariffs and legal assistance. These activities are:

1. Adapt the bulk power tariff and avoided cost developed in the tariff study to specific power plants, and assist PPGC in negotiation of power delivery agreements;

2. Develop a method of price indexation to adjust the prices given in power purchase agreements, to account for inflation, exchange rates, and fuel costs.

Poland has nearly 400 powerplants and combined heat and power stations with an installed capacity of 29,627 MW. Almost all of the country's electric energy is produced by lignite- and coal-fired power stations, many of which have severe environmental impacts. Lignite-fired plants produce the lowest-cost energy (if environmental costs are ignored), and contribute 43% of total production.

The facilities are currently operated by 32 generating companies, 23 combined-heat and power companies, a national transmission company (Polskei Sieci Elektroenergotyczne, or Polish Power Grid Company, PPGC) and 33 distribution companies. However, as part of the energy sector restructuring program, these entities are expected to be reorganized into a fewer number of generation and distribution companies. Because of the recent fall in electric sales, new generation capacity is not immediately required. However, massive investments are necessary to reduce environmental emissions and improve efficiency to reasonable levels.

Over the past four years, the Government of Poland (GOP) has begun to introduce sweeping legal and regulatory reforms to accelerate the transition to a market-oriented economy. The GOP



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has recognized the key role of the energy sector in this fundamental transformation, both in terms of its importance to other sectors as well as its own investment needs. Consequently, the GOP initiated the Energy Sector Restructuring, Privatization, and Regulatory Reform Program. This program aims to liberalize energy prices, promote enterprise competition within the energy sector, and transform the ownership, control, and operation of state-owned enterprises in a manner consistent with a market model of the energy sector.

PPGC has already been reorganized as a joint stock company, currently owned by the National Treasury. It will retain its role as the single national transmission company. Currently it is also responsible for system planning, dispatch, and control, bulk power purchases and sales, and retail tariff recommendations. It is expected that a regulatory agency will be established as part of an "energy law," which is currently under preparation. This agency will supervise the operation of the power market.

## Specific Goals and Objectives

The objective of this task is to assist Poland in the development of privatization and restructuring in the power sector by providing the contractual framework, pricing methodology and purchase prices necessary for the private sector to rehabilitate and develop power projects.

## Expected Outputs

This task is expected to result in the following outcomes:

- Agreement between PPGC and four CHP plants on pricing conditions
- Capability in PPGC to calculate avoided costs as a reference for pricing other power purchases from non-grid (i.e. cogenerators and autoproducers) powerplants.
- Pricing terms for grid powerplants (i.e. conventional power only plants) based on standard cost components as opposed to the current system based on plant specific costs.
- A plan for the transition from plant specific costs to standard costs in grid powerplants.
- Agreement at PPGC on a criterion for qualifying a power plants as either a CHP or grid power plants.

**Deliverables**

This task will produce the following deliverables:

Trip reports
- 1 copy to AID/EUR
- 1 copy to AID/Warsaw

Monthly reports
- 1 copy to AID/EUR
- 1 copy to AID/Warsaw

Final report
- Task Completion Memorandum to AID/EUR

**Results and Next Steps**

The result of the activity was an analytical tool for PPGC to measure the relative merits of offers of power sales from independent power producers interested in investing in Polish power plants. This tool consisted of an electronic spreadsheet model in which the terms of the a power sales offer of power sales were introduced as input as well as the cost characteristics of two typical plants that could be used in Poland. The model would then compare the power offer against the cost of power from the two typical plants to determine the return on capital of each offer.

The activity included a preliminary analysis of four offers, development of the electronic spreadsheet model, analysis of each offer with the model, comparison of results, explanation of the model to PPGC, preparation of a report on the analysis and support to PPGC in discussions with some of the IPP's.

# RECOMMENDED GUIDELINES FOR PRICING POWER DELIVERIES FROM POLISH COMBINED HEAT AND POWER (CHP) PLANTS

*Final Report*

Prepared for:

**U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT**
Bureau for Europe
Office of Development Resources
Energy and Infrastructure Division
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Prepared by:

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HB Reference No.93-D070-307

May, 1994

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2.1 Avoided Cost Concept
2.2 Fundamentals of Avoided Cost Computation
2.3 Proxy Plant Method

**Chapter 3 Avoided Cost of Polish CHP Plants**
3.1 Displaced Capacity and Energy
3.2 National Objectives Relevant to CHP Pricing
3.3 Recommended Approach for Computation of Avoided Costs

**Chapter 4 General Guidelines for Accepting and Pricing Power Deliveries**

**Chapter 5 Evaluation of Four Power Sales Proposals from CHP Plants**
5.1 Project Evaluation
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5.3 Conclusions
5.4 Recommendations

**APPENDIX**

1 Simplified Avoided Cost Evaluation Model and Procedures

2 Gorzow

3 Chorzow

4 Krakov Leg

5 Bielsko-Biala

# CHAPTER 1
# INTRODUCTION

The Polish Power Grid Company (PPGC) has determined that the power sector has the obligation to utilize all the electricity produced by combined heat and power (CHP) plants licensed as such. It has also determined that, at least in the case of privately owned CHP, their electricity output must be purchased on the basis of avoided costs, understanding this as the principle of evaluation of power in terms of the least cost to PPGC of securing power supply from alternative resources.

This approach offers the following advantages in the current context of restructuring of the Polish power sector:

- Establishes a relationship of cooperation and financial independence between the heat and power sectors
- Allows the heat sector to capture all of the benefits derived from the higher efficiency of a cogeneration process as compared to power-only or heat-only processes.
- Eliminates the need for cost allocation between the heat and power products of CHP plants.
- Protects the electricity customer by ensuring least cost of power supplies.
- Facilitates private investment in CHP plants through guaranteed purchase of their power deliveries.

As part of the assistance of the United States Agency for International Development (USAID) to the Government of Poland recommended bulk and retail power tariffs based on these assumptions were developed as well as the legal form of agreements for power purchases between PPGC and CHP plants. This report, also prepared under the auspices of USAID, presents a methodology for the computation of avoided costs and the results of its application to evaluate proposals for power deliveries made to PPGC by four groups interested in undertaking extension or improvement of existing CHP facilities. All monetary values in this report are expressed in U.S. dollars of January 1994. The rate of exchange at that time was approximately 20,000 zlotys to the U.S. dollar.

# CHAPTER 2
# AVOIDED COST OF POWER

## 2.1 AVOIDED COST CONCEPT

While the concept of evaluating power in terms of the least cost of alternative supply is very old, the expression "avoided costs" was coined in the late 1970's as the guiding principle to implement one of the provisions of the Public Utilities Regulatory Policies Act (PURPA) of the United States Government. PURPA mandated that power utilities should buy all the power that a non-utility producer could sell at a price equal than or lower than the cost that the utilities would incur in producing it themselves. While the concept is fairly simple, the actual mechanics of the computation of avoided costs can be complex and in the United States, the details of implementation are a matter of state regulatory authority.

It is important to bear in mind that, while the objectives of PURPA were those of reducing the cost of supply by encouraging competition among power producers, in Poland, electricity customers must be protected both by encouraging low prices through competition and by ensuring adequate capital investment to rehabilitate, maintain and expand the power system. This distinction is very relevant to the computation of avoided costs because an important element in the cost of power is the cost of capital to the power producer and, therefore, the avoided cost must be calculated considering any restrictions in the amount of capital available to the utility.

In the strictest sense avoided costs can be computed by comparing two least cost planning scenarios as follows:

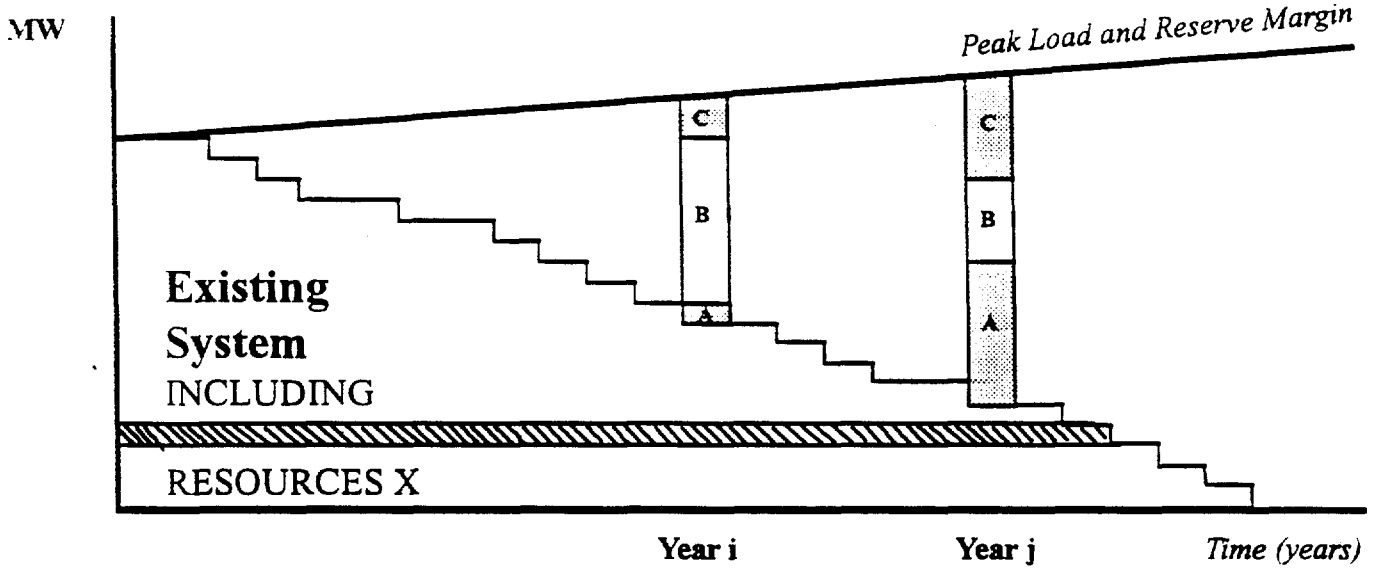
Scenario A: The capacity C and the energy E supplied annually by a given resource X is included, at no cost, in the system, thereby effectively reducing the load to be supplied by the rest of the system.

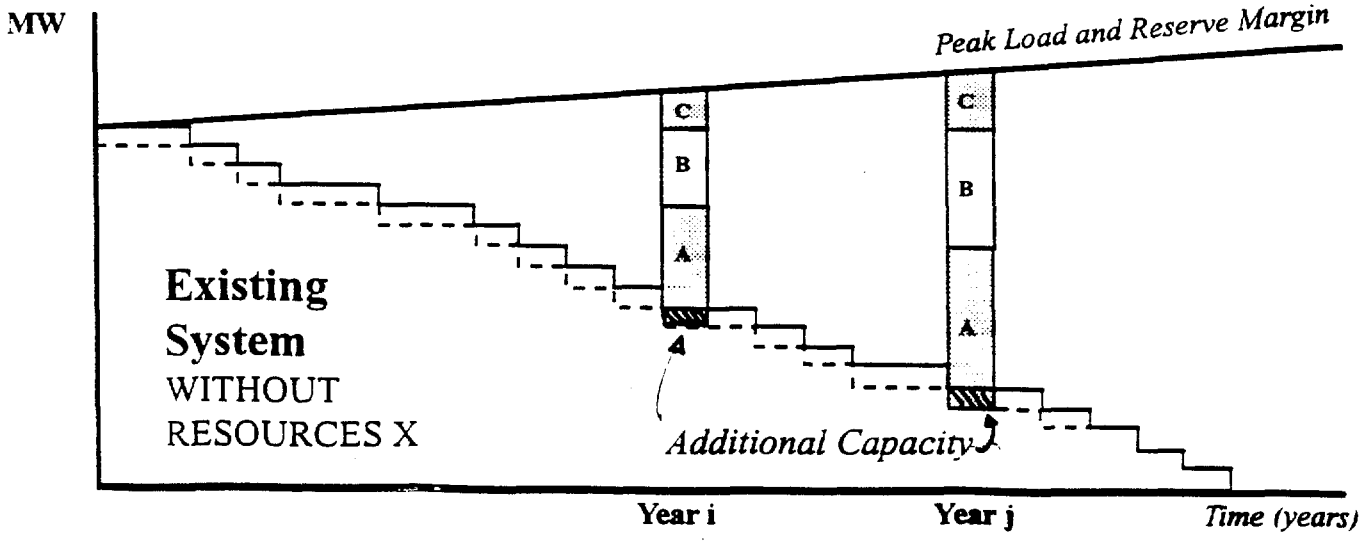
Scenario B: The resource X is eliminated from the system and additional resources may be needed to meet the higher load at the same level of reliability as before.

These scenarios are illustrated in Exhibit 2.1 which shows that in both scenarios the least cost solution to meet the growing gap between load and available resources consists of a combination of generating plants of different characteristics (shown in the exhibit as generation types A, B and C). Depending on the characteristics of the power supplied by resource X the proportion of plants of different types may be different.

EXHIBIT 2-1

# COMPUTATION OF AVOIDED COSTS AND RESOURCE EVALUATION



## 2.2 FUNDAMENTALS OF AVOIDED COST COMPUTATION

If the accumulated present value of all annual costs under scenarios A and B is denoted as $PVT_a$ and $PVT_b$ respectively then the total avoided cost of energy from resource X is:

$$ACT = (PVT_b - PVT_a)/PVE$$

Where PVE is the accumulated present value of annual energy supplied from resource X.

An analogy with conventional project evaluation follows from the computation of $PVT_b$ and $PVT_a$ are repeated for different discount rates. If I is the investment in project X then the internal rate of return of the project is the discount rate that results in
$I = PVT_b - PVT_a$

Additional computations lead to disaggregation of avoided costs of capacity and energy as follows:

Avoided cost of capacity: $ACC = (PVF_b - PVF_a)/PVC$

Where: PVF = accumulated present value of fixed costs
PVC = accumulated present value of annual capacity sales

and

Avoided cost of energy: $ACE = (PVV_b - PVV_a)/PVE$

Where: PVV = accumulated present value of annual variable costs

## 2.3 PROXY PLANT METHOD

While the computations above appear to be simple, the process of optimization of the generation expansion plan to obtain PVT, PVF and PVV for the two scenarios described above is complex, requires advanced computer models and often lengthy processing time. Even though some models can be simple enough to produce fast results there remain compelling reasons to simplify the computation of avoided costs as much as possible:

- Since the computation of avoided costs is often the basis for negotiating a power purchase agreement it is necessary to have full transparency regarding the assumptions and the computation process. This cannot be achieved with a long term generation expansion optimization model.

- It is often agreed that some terms (typically fuel) of the avoided cost are to be periodically adjusted in response to fluctuations in the market and therefore a simple formulation or computation of the adjustable term is desirable.

In order to simplify the process, a combination of plants can be used to represent the long term difference in installed capacity between scenarios A and B and the long term difference in energy production between scenarios A and B. In some cases, a single proxy plant is chosen, corresponding roughly to a project with similar characteristics to the one under evaluation (resource X).

This is known as the "proxy plant" method an essentially consists of replacing the lengthy and complex process of computing the differences in PVT, PVF, and PVV, between two scenarios by the lifetime costs of selected plants.

# CHAPTER 3
# AVOIDED COST OF POLISH CHP PLANTS

## 3.1 DISPLACED CAPACITY AND ENERGY

Because the demand for electricity fluctuates with time the least cost of power supply is normally found in a combination of generating plants. Some plants are the most economic resource to operate in a continuous manner (base-load plants) and some are the most economic resource to meet intermittent or short duration loads (peak-load plants). The Polish power generation system exhibits two peculiar characteristics that have an important impact on the computation of avoided costs:

- The system has a much higher proportion of base-load generating plants than would be selected on the basis of economic generation mix if the system were to be designed and constructed entirely today.

- The system has a higher capacity reserve than needed in the short term to meet the load with adequate reliability.

As a consequence of these two facts, it must be expected that, in the short and medium term, any additional load in the system will result in the following:

- The additional capacity required to maintain constant reliability will be less than the added peak load.

- Any required additional capacity will largely be in peak-load generating plants.

- The additional energy demand will not be entirely met by the additional capacity but rather by a combination of the new capacity plus the cheaper surplus energy available from existing and under utilized base-load plants.

This conclusion enables us to anticipate that fixed avoided costs will likely be strongly influenced by the fixed costs of alterative peak-load plants such as gas turbine plants or pumped storage hydroelectric plants whereas the variable avoided costs will be strongly influenced by base-load plants such as coal or gas fired steam turbine plants or run-of-river hydroelectric plants.

An analysis of the proportions of capacity and energy displaced by the current block of CHP plants from base-load and peak-load resources was carried out using a computer

model to estimate the annual least cost generation mix for the system during the period 1996-2016 with and without the current CHP capacity in the system. The results of the analysis are shown in Exhibit 3.1 and discussed below.

As of 1992 installed capacity in CHP plants totalled 3,884 MW with a combined peaking capability of approximately 2,350 MW. The energy production of this capacity as controlled by the needs of the cogeneration process is approximately 13,245 MWh per year. If the peaking capability of CHP plants did not continue to be available during the period 1996-2016, the least cost solution involving power-only plants would be to first install only peak-load plants until the ideal generation mix is reached and then continue with the addition of both base-load and peak-load plants to maintain the least cost generation mix. On a levelized basis, the annual additions of capacity from peak-load plants account for almost 98 % of the total capacity added to replace the current peaking capability of CHP plants. On the other hand, if current energy production of CHP plants had to be replaced by production from power-only plants, 35% percent of that production would come from the new capacity from replacement peak-load plants and 65% would come from existing or replacement base-load plants.

The results above assume that natural gas prices will not escalate faster than coal prices otherwise the proportions of coal fired capacity and energy would be higher. Also, while the actual proportions are of course likely to change slightly using different models or different assumptions, the fundamental character of surplus base-load capacity in the system would not change the basic conclusions.

## 3.2 NATIONAL OBJECTIVES RELEVANT TO CHP PRICING

While the principle of avoided cost is a sound basis for compensation of power from CHP plants, the details of its implementation must be drafted with due regard to all aspects of regulatory policy in Poland. Among the different and sometimes conflicting objectives that must be weighted in arriving at a specific pricing criterion are the following:

- ***Least Cost of Power Supply***

  The fundamental responsibility of the Polish Power Grid Company is to ensure the least cost of reliable power supply in the country compatible with other objectives affecting different sectors of the national economy.



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# EXHIBIT 3–1

## DIFFERENTIAL CAPACITY AND ENERGY PRODUCTION OF BASE–LOAD AND PEAK–LOAD POWER–ONLY PLANTS REPLACING CURRENT POWER FROM CHP PLANTS AT LEAST COST

| | NUMBER OF UNITS | | INSTALLED CAPACITY (MW) | | PRESENT VALUE | | ENERGY PRODUCTION (GWH) | | PRESENT VALUE | |
|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | BASE–LOAD | PEAK–LOAD | BASE–LOAD | PEAK–LOAD | BASE–LOAD | PEAK–LOAD | BASE–LOAD | PEAK–LOAD | BASE–LOAD | PEAK–LOAD |
| 1996 | 0 | 23 | 0 | 2760 | 0 | 2744 | 12598 | 646 | 12527 | 643 |
| 1997 | 0 | 23 | 0 | 2760 | 0 | 2450 | 12533 | 711 | 11127 | 631 |
| 1998 | 0 | 24 | 0 | 2880 | 0 | 2283 | 12426 | 818 | 9850 | 649 |
| 1999 | 0 | 23 | 0 | 2760 | 0 | 1953 | 12087 | 1157 | 8555 | 819 |
| 2000 | 0 | 23 | 0 | 2760 | 0 | 1744 | 11770 | 1475 | 7438 | 932 |
| 2001 | 0 | 24 | 0 | 2880 | 0 | 1625 | 10136 | 3108 | 5719 | 1754 |
| 2002 | 0 | 23 | 0 | 2760 | 0 | 1390 | 7938 | 5306 | 3999 | 2673 |
| 2003 | 0 | 23 | 0 | 2760 | 0 | 1241 | 5747 | 7497 | 2585 | 3372 |
| 2004 | 0 | 24 | 0 | 2880 | 0 | 1157 | 3679 | 9565 | 1478 | 3841 |
| 2005 | 0 | 24 | 0 | 2880 | 0 | 1033 | 3262 | 9983 | 1170 | 3580 |
| 2006 | 0 | 23 | 0 | 2760 | 0 | 884 | 2852 | 10392 | 913 | 3327 |
| 2007 | 0 | 23 | 0 | 2760 | 0 | 789 | 2817 | 10427 | 805 | 2981 |
| 2008 | 0 | 23 | 0 | 2760 | 0 | 704 | 2638 | 10607 | 673 | 2707 |
| 2009 | 0 | 23 | 0 | 2760 | 0 | 629 | 2209 | 11035 | 503 | 2515 |
| 2010 | 0 | 24 | 0 | 2880 | 0 | 586 | 2058 | 11187 | 419 | 2276 |
| 2011 | 0 | 23 | 0 | 2760 | 0 | 501 | 1828 | 11417 | 332 | 2074 |
| 2012 | 1 | 20 | 360 | 2400 | 58 | 389 | 3783 | 9461 | 614 | 1535 |
| 2013 | 2 | 17 | 720 | 2040 | 104 | 295 | 5809 | 7435 | 841 | 1077 |
| 2014 | 3 | 15 | 1080 | 1800 | 140 | 233 | 7905 | 5340 | 1022 | 691 |
| 2015 | 3 | 14 | 1080 | 1680 | 125 | 194 | 7906 | 5339 | 913 | 616 |
| 2016 | 3 | 15 | 1080 | 1800 | 111 | 186 | 7905 | 5340 | 815 | 550 |
| **AVOIDED COSTS 1996–2016:** | | | | | | | | | | |
| MEAN ANNUAL VALUES | 0.57 | 21.62 | 206 | 2594 | 26 | 1096 | 6661 | 6583 | 3443 | 1869 |
| PROPORTIONS (2) | 2.6% | 97.4% | 7.3% | 92.7% | 2.3% | 97.7% | 50.3% | 49.7% | 64.8% | 35.2% |
| **AVOIDED COSTS 2014–2016:** | | | | | | | | | | |
| MEAN ANNUAL VALUES | 3.00 | 14.67 | 1080 | 1760 | 125 | 204 | 7905 | 5340 | 917 | 619 |
| PROPORTIONS (2) | 17.0% | 83.0% | 38.0% | 62.0% | 38.0% | 62.0% | 59.7% | 40.3% | 59.7% | 40.3% |

**NOTES:**

1. RESULTS OBTAINED FROM EXPANSION OF THE SYSTEM WITH AND WITHOUT THE CHP COMPONENT USING MODEL GPT
2. THE PROPORTIONS OF BASE–LOAD AND PEAK–LOAD ARE BASED ON THE PRESENT VALUE OF DIFFERENTIAL CAPACITY AND PRODUCTION
3. BASE–LOAD UNIT IS A COAL FIRED 360 MW STEAM TURBINE
4. PEAK–LOAD UNIT IS A 120 MW GAS FIRED COMBUSTION TURBINE
5. NO REAL ESCALATION OF FUEL PRICES ASSUMED

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- ***Private Sector Financing of the Power System***

  The Government of Poland believes that the power industry is a commercially viable activity that should be undertaken by the private sector thereby freeing the financial resources of the state to support other activities.

- ***Scarcity of Public Financing to the Power Sector***

  The Government's interest in promoting the participation of the private sector in power production is one of the main elements of national economic reform. Independently of this political objective, the capability of the state to finance investments in the power sector is limited when compared to the investment requirements imposed by other policy decisions such as environmental control targets and the standards of operational performance required to effectively link the Polish power system to that of western Europe.

- ***Cooperation with the District Heating Industry***

  The obligation of the power sector to purchase all the power production of CHP plants at fair prices is a policy of the Government of Poland and reflects the cooperation that must exist between these two industries of primary importance value to social welfare.

In addition to representing a reasonable compromise of the above stated objectives the rules of pricing must be sufficiently general to ensure fairness to all suppliers while maintaining a degree of flexibility to take into account such project specific features as equipment reliability and flexibility of dispatch.

As a first step, a simple formulation of the computation of avoided costs is needed such that it can be easily understood by all concerned parties and regularly updated and revised as required under changing conditions and forecasts.

## 3.3 RECOMMENDED APPROACH FOR COMPUTATION OF AVOIDED COSTS

Based on the detailed analysis of the system through the use of advanced generation expansion optimization models it is possible to obtain the proportions of capacity and energy displaced by base-load and peak-load resources and use these to develop a simplified algorithm for the computation of avoided costs. This algorithm is programmed into a simple spreadsheet model that eliminates the need for continuous reference to advanced generation expansion models.

Essentially, the model consists of the computation of fixed and variable cost for two proxy plants. A weighted average fixed reference cost is computed from the proportion of capacity that each alternative (base-load or peak-load) contributes to replace the capacity currently supplied by the CHP component. A weighted average variable reference cost is computed from the proportion of energy production that each alternative contributes to replace the energy currently supplied by the CHP component.

A detailed description of the spreadsheet model is presented in Appendix 1 which includes a copy of the spreadsheet model to be accessed via Lotus 123 version 3.2 or compatible calculation sheet software.

The model has been designed to evaluate a power sales proposal from three different perspectives:

- ***Avoided Cost***

  In this case the reference fixed and variable costs are strict avoided costs since the proportions of displaced capacity and energy from the base-load and peak-load proxy plants are obtained from the levelized values discussed above. That is, the fixed reference cost consists of 2.3% fixed costs of the base-load proxy plant and 97.7% fixed costs of the peak-load proxy plant and the variable reference cost consists of 64.8% variable cost of base-load plant and 35.2% variable cost of peak-load plant.

- ***Mature Avoided Cost***

  This case is designed to examine how the power sales proposal would look if the generation mix were currently in the correct balance between base-load and peak-load plants. In this case the fixed reference cost consists of 38% fixed costs of the base-load proxy plant and 62% fixed costs of the peak-load proxy plant and the variable reference cost consists of 59.7% variable cost of base-load plant and 40.3% variable cost of peak-load plant.

- ***Similar Project Cost***

  This case is designed to examine how the power sales proposal looks against the cost of developing a power-only alternative of similar characteristics to the proposed source of power in terms of technology and fuel.

  Under any of these cases the model works as follows:

  Step 1. The reference fixed and variable costs are calculated according to the criteria applicable to the particular case above. The fixed



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reference cost is the annual lifetime cost obtained from the annual fixed operating costs and the amortization of capital investments using a discount rate deem to reflect the current capital cost of the utility. This discount rate does not account for capital scarcity (i.e. any limitations on borrowing that the utility might have and which of course renders impossible an independent determination of capital cost). This issue will be investigated a posteriori.

Step 2. The proposed fixed annual payments (capacity payments) are converted into equivalent fixed annual payments by adding to the proposed fixed annual payments the product of the proposed annual energy sales times the difference between the proposed energy price and the reference energy price. Thus, any differences between reference variable costs and proposed energy price are accounted for in the equivalent proposed fixed annual payments.

Step 3. The equivalent fixed annual payment is levelized using the same discount rate as in step 1 and then divided by the amount of peaking capability (net of any losses) that is deemed to be deliverable to the grid.

Step 4 The equivalent fixed annual payment ($/KW) is compared to the reference fixed cost. The difference reflects the higher or lower annual unit cost to the utility of obtaining power from the resource under evaluation.

Step 5 The discount rate used in step 1 is revised until the annuitized reference cost matches the equivalent annual payment. The resulting discount rate represents the cost of capital of the utility if all power were to be procured under the same terms as those of the project under evaluation.

When a specific proposal is analyzed under all three perspectives defined above it is possible to determine to what extent the proposal is being affected by current departures from the optimum generation mix and to what extent the proposal suffers from the natural disadvantage of any single generation resource over a generating utility that can decouple the fixed and variable costs of power through the use of a combination of different resources. These elements, combined with considerations of reliability, flexibility of dispatch, environmental advantage and other issues of interest to the utility must be used in reaching a final decision or proposing revision to the power sales offer.



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# CHAPTER 4
# GENERAL GUIDELINES FOR ACCEPTING AND PRICING POWER DELIVERIES

The obligation to purchase power from CHP plants places an important operational constraint on the dispatch of the generation system. At the same time, payment to CHP on the basis of avoided costs and guaranteed purchase may result in a preferential status with respect to other producers. Therefore PPGC needs to clearly define the criteria to be met by a power supplier to qualify as a CHP supplier and by power deliveries to qualify as CHP deliveries that PPGC is obliged to accept.

While specific pricing terms may be defined for each individual case based on the simplified analysis of avoided costs discussed above, it is recommended that a set of General Guidelines be established as follows:

- Power purchased on the basis of avoided costs must be produced at a qualifying CHP plant. A qualifying CHP plant is a plant built primarily to supply heat to a district heating network and the majority of its heat input during any consecutive 12 months must be output to the district heating network.

- PPGC has the obligation to purchase all power produced by a qualifying CHP plant and produced in a specific cogeneration process where the majority of the heat input is output to a district heating network. Such power will be designated as Qualifying (Q) Power.

- Power produced in a qualifying CHP facility but not produced in a cogeneration process where the majority of the heat input is output to a district heating network will be designated as Non-Qualifying (NQ) Power. The CHP plant must declare the Q or NQ character of all power deliveries as well as state what portion, if any, of NQ power was delivered at the request of PPGC.

- The CHP facility must coordinate with PPGC all power deliveries indicating estimated quantities of Q and NQ power that will be delivered and estimated additional Q and NQ power available.

- All Q power and the available NQ power requested by PPGC will be purchased on the basis of total avoided costs and will include the fair replacement cost of both capacity and energy. NQ power delivered but not

at the request of PPGC will be purchased on the basis of avoided energy costs only.

- PPGC may withhold payment of unrequested NQ power deliveries that result, over any 12 consecutive month period, in a majority of heat input being used for power generation and credit such payment towards future Q power deliveries or requested NQ power deliveries.

These guidelines guarantee the right of CHP plants to a fair price for all deliveries of power produced in a process primarily intended for district heating. They also recognize the occasional need of CHP to deliver power from a power-only process or at low levels of heat demand as well as the opportunity for PPGC to request power deliveries beyond those associated with the demand for heat.

# CHAPTER 5
# EVALUATION OF FOUR POWER SALES PROPOSALS FROM CHP PLANTS

## 5.1 PROJECT EVALUATION

PPGC has received proposals of power sales from four CHP plants: CHP Gorzow, CHP Chorzow, CHP Krakov Leg and CHP Bielsko-Biala. The proposed projects range in size from 50 to 454 Mw with varying levels of energy production which yield capacity factors ranging from 66% to 81%.

A detailed evaluation of each project is presented in Appendices 2 to 5 which contain the detailed reports produced by the Purchase Power Agreement Evaluation (PPAE) spreadsheet developed for this purpose and described in detail in Appendix 1.

Each proposed project has been evaluated by comparing the revenues sought by the offeror against a reference value to PPGC of the power offered for sale. This section focuses on a comparative analyses of results, the detailed data and analysis of results for specific projects are described in the respective appendices.

The benefit of each power sales proposal to PPGC is computed from the three alternative perspectives discussed in Chapter 3 above: Avoided Costs, Mature Avoided Costs and Similar Project Costs. A comparison of results for all four projects under each perspective is shown in Exhibits 5.1 to 5.3. Each table is divided into four sections: Project Characteristics, Unit Costs and Benefits, Total Costs and Benefits and Equivalent Cost of Capital. A brief description of each section follows.

Under the first section (Project Characteristics) is shown the capacity, production and capacity factor for each project as well as for the existing CHP block of plants which are used as a reference to determine the least cost combination of replacement with power-only plants. The reduction from nameplate to useful capacity shown in the tables results from the anticipated losses for station service and the useful capacity is the peaking capability deemed deliverable to the grid.

The next section (Unit Values) contains several groups of data as follows:

*Unadjusted Unit Costs*

In the case of the four projects under evaluation this group of data shows the fixed and variable levelized annual costs derived from the payment schedule included in each of the proposals. Also included are the fixed and variable levelized least costs of replacement the block of all existing CHP plants with power only units. ~~Applying the corresponding capacity factor to the fixed and variable costs in each case results in the total cost of power in kWh.~~

*Costs Adjusted to Uniform Energy Price*

This group of data shows the result of making a transfer between fixed and variable costs so that the proposed variable (energy) payments of all projects is constant and equal to the strict variable avoided cost. Note that the total cost of power remains the same in all cases and the fixed cost has been adjusted to reflect the difference in annual revenues between the proposed energy (variable) payments and the reference variable cost.

*Reference Cost adjusted by Capacity Factor*

This line simply reflects the total reference cost derived from the fixed and variable reference costs but computed at the capacity factor proposed for each individual project.

*Cost (Savings) to PPGC*

This group of results show the annual cost (saving) to PPGC of accepting the proposed project when compared to the reference case shown both in ~~$/Kw~~ or kWh.

The next section (Annual Values) shows the same information but in terms of total annual proposed payments against total annual benefits as computed in terms of the reference case.

The last part of the table (Cost of Capital) shows the discount rate that would result in the reference case having the same annual cost of power as that of the proposed sale. This equalizing discount rate can be interpreted as follows:

*True Cost of Capital of Power Supply*

If the proposals under evaluation are the result of a solicitation process and thus are deemed to be the *best offers available to PPGC* and, furthermore, PPGC has

*no possibility of raising capital for power supply projects*, then the equalizing discount rate represents the true cost of capital to PPGC for power supply projects.

Under the above assumptions the value of the equalizing discount rate should not be an issue in absolute terms since there is no cheaper way to secure the supply of power. The only issue is the relative equalizing discount rates among the different offers which must be weighted against other evaluation criteria such as power reliability and flexibility of dispatch.

*Cost of Non-Utility Supply*

If PPGC had the possibility of raising capital to develop the projects at a given interest rate then the difference between the equalizing discount rate and the interest rate that PPGC would pay to finance the projects itself is the cost of seeking power supplies from non-utility sources. This difference must be weighted against the benefits derived from not compromising the financial resources of PPGC to power supply projects.

## 5.2 SUMMARY OF RESULTS

***Reference Case = Strict Avoided Costs***

This case is presented in Exhibit 5.1 which shows that the proposal from CHP Gorzow is the most expensive in terms of total unit price of power at 2.64 Cts/Kwh above PPGC's strict avoided cost of power. CHP Chorzow and Krakov Leg follow at 1.83 Cts/Kwh and 1.16 Cts/Kwh respectively. CHP Bielsko Biala on the other hand results in a benefit of 0.4 Cts/Kwh with respect to PPGC's avoided cost.

***Reference Case = Mature Avoided Costs***

This case, presented in Exhibit 5.2, reflects the result of accepting as a reference the avoided cost of replacing the existing CHP block but not under the conditions prevailing today in terms of generation mix but those that should prevail if the system had a balanced mix of base-load and peak-load plants. In other words, this case eliminates any penalty imposed due to the excessive amount of base-load capacity currently in the system.



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The relative ranking of proposals is the same. The cost of power from Gorzow and Chorzow is still substantially higher than reference costs (1.76 Cts/Kwh and 0.95 Cts/Kwh respectively). Power from Krakov-Leg is now at nearly the reference cost and power from Bielsko-Biala offers a substantial savings (1.43 Cts/Kwh) with respect to PPGC's costs.

***Reference Case = Similar Project Costs***

Shown in Exhibit 5.3 are the results of using as a reference the expected cost to PPGC of building a power-only plant of similar characteristics as the proposed source of supply in terms of technology and fuel. Thus, the proposal from CHP Gorzow is compared to a combined cycle plant fueled with natural gas while all the others are compared against a coal fired steam turbine plant.

The results are not very different from the previous case. CHP Gorzow and CHP Chorzow still show a cost of power substantially above the reference cost while Krakov-Leg now offers modest savings and Bielsko-Biala substantial savings.

## 5.3 CONCLUSIONS

The results summarized above suggest the following conclusions:

- It is viable to obtain power from a CHP plant at a cost below that of PPGC's avoided costs. However, only one proposal (Bielsko-Biala) is viable under a strict application of the avoided cost criterion while the viability of the others depends on the actual constraints of PPGC of raising capital at or below 12 percent interest per year in real terms.

- If the proposals are deemed representative of the expectations of the private sector to become involved in power supply then PPGC's must expect that power supplies from the private sector will have a financial impact equivalent to raising its own cost of capital at least 10 to 15 points above its current cost of commercial borrowing. ~~from non-utility sources.~~

## 5.4 RECOMMENDATIONS

- Inasmuch as the reliability of the machines and the flexibility of dispatch involved in each of the four proposals has not been explored in detail, it will be necessary to qualify these aspects before arriving at a final ranking of the four projects.

- Under equal terms of dispatch and reliability the proposal from Bielsko-Biala appears to be favorable to PPGC and it is recommended that steps be taken to enter into an agreement with this plant.

- PPGC should solicit power from other resources in order to compare proposals from power-only plants, particularly peak-load type of plants, in order to establish ~~what are~~ the real costs of non-utility power as determined by competitive bidding.

- The power proposals from CHP Gorzow and Chorzow appear to be very far from PPGC's avoided costs. The proposal from CHP Krakov-Leg merits further consideration with due regard to the benefits to other sectors such as environment and heat supply.

EXHIBIT 5-1

# COMPARISON OF FOUR PROPOSED CHP PROJECTS
## REFERENCE: STRICT AVOIDED COST

| | | REFERENCE | POWER SALES PROPOSAL | | | |
|---|---|---|---|---|---|---|
| | | ALL CHP | GORZOW | CHORZOW | KRAKOV LEG | BIELSKO BIALA |
| **PROJECT CHARACTERISTICS** | | | | | | |
| CAPACITY | | | | | | |
| NAMEPLATE | MW | 3,884 | 50.0 | 190.0 | 454.0 | 111.0 |
| USEFUL TO PSE | MW | 2,350 | 44.2 | 175.0 | 334.0 | 102.0 |
| PRODUCTION | MWh | 13,245,000 | 314,184 | 1,235,539 | 1,978,000 | 596,400 |
| CAPACITY FACTOR | | 64.3% | 81.1% | 80.6% | 67.6% | 66.7% |
| **UNIT VALUES** | | | | | | |
| UNADJUSTED UNIT COSTS | | | | | | |
| FIXED | $/kW | 78.53 | 343.45 | 262.99 | 188.05 | 106.93 |
| VARIABLE | c/kWh | 2.99 | 1.90 | ~~2.21~~ | ~~2.30~~ | ~~2.11~~ |
| TOTAL | c/kWh | 4.38 | 6.73 | ~~5.93~~ | ~~5.48~~ | ~~3.94~~ |
| COSTS ADJUSTED TO UNIFORM ENERGY PRICE | | | | | | |
| FIXED | $/kW | na | 265.89 | 207.78 | 147.24 | 55.39 |
| VARIABLE | c/kWh | na | 2.99 | 2.99 | 2.99 | 2.99 |
| TOTAL | c/kWh | na | 6.73 | 5.93 | 5.48 | 3.94 |
| REFERENCE COST ADJUSTED BY CAPACITY FACTOR OF PROPOSED DELIVERIES | | | | | | |
| FIXED | $/kW | na | 78.53 | 78.53 | 78.53 | 78.53 |
| VARIABLE | c/kWh | na | 2.99 | 2.99 | 2.99 | 2.99 |
| TOTAL | c/kWh | na | 4.10 | 4.10 | 4.32 | 4.33 |
| COST (SAVINGS) TO PPGC | | | | | | |
| FIXED | $/kW | na | 187.36 | 129.25 | 68.71 | (23.14) |
| TOTAL | c/kWh | na | 2.64 | ~~1.83~~ | ~~1.16~~ | ~~(0.40)~~ |
| **ANNUAL VALUES** | | | | | | |
| COSTS ADJUSTED TO UNIFORM ENERGY PRICE | | | | | | |
| FIXED | K$ | na | 11,752 | 36,361 | 49,179 | 5,650 |
| VARIABLE | K$ | na | 9,398 | 36,958 | 59,167 | 17,840 |
| TOTAL | K$ | na | 21,150 | ~~73,319~~ | ~~108,345~~ | ~~23,490~~ |
| AVERAGE PRICE | c/kWh | na | 6.73 | ~~5.93~~ | ~~5.48~~ | ~~3.94~~ |
| REFERENCE COST ADJUSTED BY CAPACITY FACTOR OF PROPOSED DELIVERIES | | | | | | |
| FIXED | K$ | na | 3,471 | 13,742 | 26,229 | 8,010 |
| VARIABLE | K$ | na | 9,398 | 36,958 | 59,167 | 17,840 |
| TOTAL | K$ | na | 12,869 | 50,700 | 85,395 | 25,850 |
| AVERAGE PRICE | c/kWh | na | 4.10 | 4.10 | 4.32 | 4.33 |
| COST (SAVINGS) TO PPGC | | | | | | |
| AMOUNT | K$ | na | 8,281 | 22,619 | ~~22,950~~ | ~~(2,360)~~ |
| % DIFFERENCE | | na | 64.3% | ~~44.6%~~ | ~~26.9%~~ | ~~-9.1%~~ |
| **COST OF CAPITAL** | | | | | | |
| EQUIVALENT COST OF CAPITAL | | 12.00% | 40.17% | 32.92% | 24.28% | 6.47% |
| PREMIUM OVER PPGC BORROWING COST | | 0.00% | 28.17% | 20.92% | 12.28% | -5.53% |

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EXHIBIT 5-2

# COMPARISON OF FOUR PROPOSED CHP PROJECTS
# REFERENCE: MATURE SYSTEM AVOIDED COST

| | | REFERENCE CASE | PROPOSED PROJECT | | | |
|---|---|---|---|---|---|---|
| | | MATURE SYSTEM | GORZOW | CHORZOW | KRAKOV LEG | BIELSKO BIALA |
| **PROJECT CHARACTERISTICS** | | | | | | |
| CAPACITY | | (CHP BLOCK) | | | | |
| NAMEPLATE | MW | 3,884 | 50.0 | 190.0 | 454.0 | 111.0 |
| USEFUL TO PSE | MW | 2,350 | 44.2 | 175.0 | 334.0 | 102.0 |
| PRODUCTION | MWh | 13,245,000 | 314,184 | 1,235,539 | 1,978,000 | 596,400 |
| CAPACITY FACTOR | | 64.3% | 81.1% | 80.6% | 67.6% | 66.7% |
| **UNIT VALUES** | | | | | | |
| UNADJUSTED UNIT COSTS | | | | | | |
| FIXED | $/kW | 131.33 | 343.45 | 262.99 | 188.05 | 106.93 |
| VARIABLE | c/kWh | 3.12 | 1.90 | 2.21 | 2.30 | 2.11 |
| TOTAL | c/kWh | 4.52 | 6.73 | 5.93 | 5.48 | 3.94 |
| COSTS ADJUSTED TO UNIFORM ENERGY PRICE | | | | | | |
| FIXED | $/kW | na | 265.89 | 207.78 | 147.24 | 55.39 |
| VARIABLE | c/kWh | na | 2.99 | 2.99 | 2.99 | 2.99 |
| TOTAL | c/kWh | na | 6.73 | 5.93 | 5.48 | 3.94 |
| REFERENCE COST ADJUSTED BY CAPACITY FACTOR OF PROPOSED DELIVERIES | | | | | | |
| FIXED | $/kW | na | 140.82 | 140.76 | 139.24 | 139.14 |
| VARIABLE | c/kWh | na | 2.99 | 2.99 | 2.99 | 2.99 |
| TOTAL | c/kWh | na | 4.97 | 4.98 | 5.34 | 5.37 |
| COST (SAVINGS) TO PPGC | | | | | | |
| FIXED | $/kW | na | 125.06 | 67.02 | 8.00 | (83.74) |
| TOTAL | c/kWh | na | 1.76 | 0.95 | 0.14 | (1.43) |
| **ANNUAL VALUES** | | | | | | |
| COSTS ADJUSTED TO UNIFORM ENERGY PRICE | | | | | | |
| FIXED | K$ | na | 11,752 | 36,361 | 49,179 | 5,650 |
| VARIABLE | K$ | na | 9,398 | 36,958 | 59,167 | 17,840 |
| TOTAL | K$ | na | 21,150 | 73,319 | 108,345 | 23,490 |
| AVERAGE PRICE | c/kWh | na | 6.73 | 5.93 | 5.48 | 3.94 |
| REFERENCE COST ADJUSTED BY CAPACITY FACTOR OF PROPOSED DELIVERIES | | | | | | |
| FIXED | K$ | na | 6,224 | 24,632 | 46,505 | 14,192 |
| VARIABLE | K$ | na | 9,398 | 36,958 | 59,167 | 17,840 |
| TOTAL | K$ | na | 15,622 | 61,590 | 105,672 | 32,032 |
| AVERAGE PRICE | c/kWh | na | 4.97 | 4.98 | 5.34 | 5.37 |
| COST (SAVINGS) TO PPGC | | | | | | |
| AMOUNT | K$ | na | 5,528 | 11,729 | 2,673 | (8,542) |
| % DIFFERENCE | | na | 35.4% | 19.0% | 2.5% | -26.7% |
| **COST OF CAPITAL** | | | | | | |
| EQUIVALENT COST OF CAPITAL | | 12.00% | 21.78% | 17.63% | 12.75% | 1.54% |
| PREMIUM OVER PPGC BORROWING COST | | 0.00% | 9.78% | 5.63% | 0.75% | -10.46% |

EXHIBIT 5-3

# COMPARISON OF FOUR PROPOSED CHP PROJECTS
## REFERENCE: SIMILAR PROJECT AVOIDED COST

| | | REFERENCE CASE SIMILAR PROJECT | | PROPOSED PROJECT | | | |
|---|---|---|---|---|---|---|---|
| | | | | GORZOW | CHORZOW | KRAKOV LEG | BIELSKO BIALA |
| | | GAS | COAL | GAS | COAL | COAL | COAL |
| **PROJECT CHARACTERISTICS** | | | | | | | |
| CAPACITY | | | | | | | |
| NAMEPLATE | MW | na | na | 50.0 | 190.0 | 454.0 | 111.0 |
| USEFUL TO PSE | MW | na | na | 44.2 | 175.0 | 334.0 | 102.0 |
| PRODUCTION | MWh | na | na | 314,184 | 1,235,539 | 1,978,000 | 596,400 |
| CAPACITY FACTOR | | 64.3% | 64.3% | 81.1% | 80.6% | 67.6% | 66.7% |
| **UNIT VALUES** | | | | | | | |
| UNADJUSTED UNIT COSTS | | | | | | | |
| FIXED | $/kW | 135.30 | 220.88 | 343.45 | 262.99 | 188.05 | 106.93 |
| VARIABLE | ¢/kWh | 3.32 | 2.08 | 1.90 | 2.21 | 2.30 | 2.11 |
| TOTAL | ¢/kWh | 5.72 | 6.00 | 6.73 | 5.93 | 5.48 | 3.94 |
| COSTS ADJUSTED TO UNIFORM ENERGY PRICE | | | | | | | |
| FIXED | $/kW | na | na | 265.89 | 207.78 | 147.24 | 55.39 |
| VARIABLE | ¢/kWh | na | na | 2.99 | 2.99 | 2.99 | 2.99 |
| TOTAL | ¢/kWh | na | na | 6.73 | 5.93 | 5.48 | 3.94 |
| REFERENCE COST ADJUSTED BY CAPACITY FACTOR OF PROPOSED DELIVERIES | | | | | | | |
| FIXED | $/kW | na | na | 158.38 | 156.29 | 166.70 | 167.39 |
| VARIABLE | ¢/kWh | na | na | 2.99 | 2.99 | 2.99 | 2.99 |
| TOTAL | ¢/kWh | na | na | 5.22 | 5.20 | 5.81 | 5.85 |
| COST (SAVINGS) TO PPGC | | | | | | | |
| FIXED | $/kW | na | na | 107.50 | 51.49 | (19.46) | (111.99) |
| TOTAL | ¢/kWh | na | na | 1.51 | 0.73 | (0.33) | (1.92) |
| **ANNUAL VALUES** | | | | | | | |
| COSTS ADJUSTED TO UNIFORM ENERGY PRICE | | | | | | | |
| FIXED | K$ | na | na | 11,752 | 36,361 | 49,179 | 5,650 |
| VARIABLE | K$ | na | na | 9,398 | 36,958 | 59,167 | 17,840 |
| TOTAL | K$ | na | na | 21,150 | 73,319 | 108,345 | 23,490 |
| AVERAGE PRICE | ¢/kWh | na | na | 6.73 | 5.93 | 5.48 | 3.94 |
| REFERENCE COST ADJUSTED BY CAPACITY FACTOR OF PROPOSED DELIVERIES | | | | | | | |
| FIXED | K$ | na | na | 7,000 | 27,350 | 55,677 | 17,073 |
| VARIABLE | K$ | na | na | 9,398 | 36,958 | 59,167 | 17,840 |
| TOTAL | K$ | na | na | 16,398 | 64,308 | 114,844 | 34,913 |
| AVERAGE PRICE | ¢/kWh | na | na | 5.22 | 5.20 | 5.81 | 5.85 |
| COST (SAVINGS) TO PPGC | | | | | | | |
| AMOUNT | K$ | na | na | 4,752 | 9,011 | (6,499) | (11,423) |
| % DIFFERENCE | | na | na | 29.0% | 14.0% | −5.7% | −32.7% |
| **COST OF CAPITAL** | | | | | | | |
| EQUIVALENT COST OF CAPITAL | | 12.00% | 12.00% | 21.08% | 15.76% | 10.52% | 0.69% |
| PREMIUM OVER PPGC BORROWING COST | | 0.00% | 0.00% | 9.08% | 3.76% | −1.48% | −11.32% |

# APPENDIX 1

# SIMPLIFIED AVOIDED COST EVALUATION MODEL AND PROCEDURES

## 1. SPREADSHEET EVALUATION MODEL AND PROCEDURES

### 1.1 Introduction

The basic analytical tool used to determine the value to PPGC of proposals to supply new CHP resources is the Generation Planning Tools (GPT) model, a production cost and generation planning model familiar to PPGC. While GPT is not as complicated as many other system planning models, understanding such a model and feeling relatively comfortable with its results and implications is not an easy task for many who are involved with the evaluation or negotiation of proposed purchased power contracts. In order to effectively broaden the number of participants who might fully appreciate the economic parameters, a simplified spreadsheet model, based on the "proxy plant" method, was developed. The Power Purchase Agreement Evaluation (PPAE) spreadsheet is organized in six pages as follows:

| | |
|---|---|
| Page 1 | - Analysis of Reference Case |
| Page 2 | - Power Sales Proposal |
| Page 3 | - Comparison of Reference Case to Proposed Project |
| Page 4 | - Auxiliary Computations. |
| Page 5 | - Reference Case Input Data |
| Page 6 | - Summary |

In the current analysis, the PPAE has been applied to three distinct reference cases designated as follows:

- Avoided Cost
- Mature System
- Similar Project

Based on input data provided by the analyst, each of these cases may be run by selecting the appropriate item from the main menu. The menu also provides convenient access to the various pages in the analysis and the option to print selected pages.

### *Avoided Cost (AC) Reference Case*

In the Avoided Cost reference case, a combination of coal-fired and gas-fired resources is used as the criterion to evaluate the power sales proposal. The spreadsheet is designed to replicate, in a simplified manner, the results of the GPT analysis that involves the simulation of the least cost expansion of the PPGC generation system with and without the existing capacity of CHP plants. Using consistent input data at 1996 cost levels, the detailed simulation model and this simplified spreadsheet evaluation have been determined to yield comparable results. The results of applying the Avoided Cost reference case to a "Generic Project" are presented in Exhibit A1-1.

### *Mature System (MS) Reference Case*

The Mature System reference case is similar to the Avoided Cost case, except that the proportions of capacity and energy are adjusted to represent a "balanced" system expansion which would occur when the existing imbalance in base and peaking plant mix is corrected. Results of applying the PPAE model to the same generic project used above as compared to a Mature System reference case are set forth in Exhibit A1-2.

This case and the one which follows represent variations from the basic avoided cost case which are intended to provide further insight, and perhaps guidance, into the nature of PPGC's cost situation and how to fairly value the offers of third party producers.

### *Similar Project (SP) Reference Case*

A single resource can also be used in Page 1 of the PPAE to estimate, as another reference, the costs of power from a generating unit with characteristics which are similar to the power project under evaluation. This Similar Project case may be either a coal or gas-fired unit, depending upon the project being evaluated, as selected by the analyst.

In this case the fixed and variable avoided costs represent the costs that are expected to be associated with power from a project similar to that being proposed. This does not reflect the avoided cost to PPGC, since it is not the least cost combination of resources which PPGC would otherwise use to supply the power under evaluation. However, PPGC must recognize that no single project will be capable of supplying power at the average least cost associated with the long-term expansion plan and, thus, the SP case also provides a valuable reference tool for the evaluation of a specific project proposal.

The similar project case is illustrated in Exhibit A1-3 for the generic project proposal. In this case only data for a single resource is needed in Page 1. This data will reflect, as closely as possible, the cost to PPGC of developing a project similar to that proposed to supply the power under evaluation. The proportions of avoided capacity and energy will, of course, be set so that all of the required capacity and energy comes from the single



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project defined. The input data section of the model provides for both coal and gas plant parameters.

## 1.2 DESCRIPTION OF THE PPAE SPREADSHEET MODEL

The Avoided Cost case forms the basic foundation for project evaluation and will be used to explain and illustrate the use of the PPAE spreadsheet model. Please refer to Exhibit A1-1 which contains the evaluation of a generic project against the Avoided Cost reference case using this model.

### 1.2.1 Page 1 - Analysis of Reference Case

This part of the spreadsheet is used to develop the fixed and variable costs of additional power resources to PPGC based on the estimated costs of alternative, or "reference case", supplies of power. The new supply may be obtained from either a combination of resources or from one single resource.

*Input Data and Cost of Capital*

In the Avoided Cost case the overall fixed and variable costs of system resources are calculated using estimated input data for both coal-fired and gas-fired resources, using data provided by the analyst. The spreadsheet user defines two resources, a base load plant (i.e. coal fired steam turbine) and a peaking plant (i.e. gas fired combustion turbine), the type of units that would provide the bulk of added capacity in PPGC's least cost capacity expansion plan. In the example shown in Schedule 1 of Exhibit A1-1, the input data includes costs at 1996 price levels, consistent with the data used in the underlying GPT analysis.

Also shown is a real (i.e., net of inflation) cost of capital to PPGC that is defined in the lower part of the sheet as "Total Capital Cost". This cost of capital is used to calculate interest which accrues during construction and the capital annuity required to finance the unit over its useful life.

The true cost of capital to PPGC is defined under "Borrowing Cost" and should be the real cost of capital used to determine the avoided costs of power to PPGC. However, a line is included to add to the "Borrowing Cost" a "Premium" designed to calculate, and, therefore, to make explicit, the added cost of money which may be required in order to attract private investment. This investment cost premium is discussed in more detail in the section below which addresses Page 3 of the PPAE.

### *Proportions of Capacity and Energy*

The PPAE can closely approximate the avoided costs computed by a detailed GPT analysis of capacity expansion by extracting a minimum amount of information from the simulation results. Based on GPT results, the relative amount of capacity and energy production that would be supplied by coal-fired steam and gas-fired combustion turbines to replace CHP generation is calculated and used on Page 1 to give appropriate weight to the fixed and variable costs of the replacement units. These computations are detailed in the Auxiliary Computations on Page 4, which are discussed below.

### *Reference Case Summary*

On the right side of Page 1 the model shows the resulting fixed and variable avoided costs per kw and kwh, respectively, resulting from weighing the unit costs of coal and gas generators in accordance with their calculated proportionate contributions to overall system costs. Weighted plant investment costs which underlie the avoided fixed costs have been calculated, showing both direct construction costs and the accumulated, capitalized interest during the construction period.

For the avoided cost reference case, these values are 78.53 $/Kw-Yr, 2.99 ¢/Kwh and 476 $/Kw, respectively.

Also shown are the total avoided unit costs in cents per kwh for different capacity factors. Note that CHP avoided costs are lower than either coal or gas units alone at all load factors. The system is able to replace the CHP block with a high proportion of low cost gas turbine units while utilizing mostly coal (at much lower cost than gas) for energy production. This results due to the current system resource imbalance (not enough peaking units). It is a result which may be extremely difficult for any single plant to achieve.

### *Equalized Fixed Costs*

In the Avoided Cost Reference Case, equalized fixed costs are the same as those calculated for the Reference Case Summary, i.e., no adjustment has been made. However, because the other two reference cases produce unique energy and fixed cost values, direct comparison of reference case fixed cost levels requires an adjustment. Please refer to Exhibits A1-2 and A1-3 for results of the Mature System and Similar Project cases, respectively.

Therefore, the purpose of this section is to compute the resulting fixed charge when reference case energy costs have been set to the same level as those resulting from the avoided cost analysis (in this case, 2.99 ¢/Kwh). This is accomplished by multiplying the difference in energy cost levels by a given capacity factor and 8760 annual hours. The

capacity factor used in this computation is that associated with the proposed project, which is determined from the project data analyzed on Page 2.

The purpose of this calculation is to facilitate the direct comparison of different reference case results to the costs of the proposed project. By setting the energy costs to the same value, the various fixed charges can be directly compared, which would not otherwise be the case. However, please note that total reference case and equalized costs are equivalent only at the project capacity factor used to perform the computation. The degree of sensitivity to capacity factor is illustrated in the table of total unit costs vs. capacity factor.

### 1.2.2 Page 2 - Power Sales Proposal

This part of the PPAE spreadsheet captures the net fixed costs of power (total fixed costs less energy savings) to PPGC under the pricing terms as proposed by the project developers. The data required for Page 2 is ~~input~~ on Page 2A (and Page 2B, as the case may require). entered by the analyst

Annual power production in Mwh (column 5) is based on project estimates. The capacity value (Mw) which appears in the upper left area is specified by the analyst on Page 2A. However, this value must not be greater than either (a) or (b), whichever is smaller, defined as follows:

(a) Annual average capacity (annual production divided by 8760 hours) divided by 64.3%, or

(b) Demonstrated dependable capacity (as estimated by the developer or, in practice, as determined by periodic tests),

In this analysis capacity is regarded as having value only in association with actual electric energy production, which itself is a by-product of plant operations dedicated to meeting thermal production requirements. The characteristics of the existing block of CHP plants are such that, on average, the relationship between annual energy production and maximum capacity useful to PPGC is represented by a capacity factor of approximately 64.3%. This relationship is used to compute the maximum capacity which PPGC can expect to have available for its productive use, provided, however, that the computed result cannot exceed the actual maximum capability of the plant.

The first four columns show the contract and calendar year, monthly fixed payment and annual fixed payments based upon information supplied by the developers. Please note that the generic project (150 Mw nominal rated capacity; 138 Mw net) presented in this



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report has been created for illustrative purposes only and doesn't represent any specific project proposal under consideration by PPGC.

The next four columns are used to compute the annual dollar amount corresponding to the difference between the proposed sale price of energy and the level of energy costs associated with the avoided cost reference case. These energy savings (or costs) are used to adjust the project's fixed costs to facilitate the direct comparison of such costs between options, ~~similar to the equalized cost procedure applied to alternative reference cases.~~ Thus, the net fixed cost to PPGC (column 9) is the fixed price to be paid for capacity less any savings (plus additional costs) associated with energy purchases.

Column 10 corresponds to the present value of the net fixed cost payments at PPGC's cost of capital, which is equal to PPGC's borrowing cost as shown on Page 1. The sum of the discounted present value of annual net fixed payments over the life of the agreement is used to compute the levelized capacity payment shown (and verified in columns 10 and 11 to result in the same accumulated present value).

The results of the analysis of the power sales proposal are summarized at the bottom of Page 2. The net fixed costs of the proposal ~~(121.56 $/~~Kw in this case) can now be compared directly to the fixed costs of the reference case~~s~~ (since the energy costs ~~in all cases~~ have been set equal) in order to evaluate the relative attractiveness of the proposed project. This comparison is further illustrated on Page 3, as discussed below.

There is also a comparison between the total unitized energy costs under the proposed terms and under the reference case for various load factors. Note, however, consistent with the definition of useful CHP capacity as set forth above, the reference case price remains constant for all load factors between zero and 64.3%. For the Avoided Cost reference case, this means that the maximum price would be 4.39 ¢/Kwh, as shown. This is equivalent to restricting the useful capacity to no more than the value associated with a 64.3% capacity factor, applied to actual energy production.

Page 2A contains detailed input data and computations which support Page 2 (additional pages may be required in some cases). This page shows detailed development of energy savings and the net fixed costs per Mw. The table titled "Analysis of Project Operations" is intended to provide a profile of plant operations in cogeneration and condensing modes based on project data, when available, or nominal parameters otherwise. The coal-fired plant data appears here only for convenience. It shows the development of estimated new plant costs used in the Similar Project/Coal reference case.



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### 1.2.3 Page 3 - Comparison of Reference Case to Proposed Project

The first table on Page 3 demonstrates the relationship of PPGC's capital costs to the total plant investment costs ($/Kw), the annual fixed costs of that investment ($/Kw-Yr) and the average total unit costs per Kwh. In addition, PPGC's costs are compared to those proposed by the project developer to demonstrate relative benefits (or costs) as a function of costs of capital.

Line 1 always shows costs based on a cost of money equal to PPGC's borrowing costs with no additional "premium". These are the same results shown previously on Pages 1 & 2 of the PPAE (assuming the premium shown on Page 1 remains set to zero). Lines 2-10 show the results of changing the annual interest rate premium by an increment (which can be specified by the analyst) located in the upper left corner of this table. This increment will be calculated automatically for each revenue case or it may be set to any value which provides a range of data of interest to the observer. The "break-even" computation shows the interest rate premium at which the annual fixed charges to PPGC and those proposed by the developer would be equivalent.

Note that similar results can be obtained by changing the value of the "Premium To Attract Foreign Investment" included in the capital cost section on Page 1 of the PPAE. Changes in the premium rate cause values in the box to the right to increase or decrease interactively.

In the generic project case, this table shows that the proposal would be ~~43.03~~ 56.76 $/Kw or ~~$6.5~~ 7.8 M annually over PPGC's costs. PPGC would have to pay a premium on its cost of money of ~~8.12%~~ 10.32 (a total cost of capital of ~~20.12%~~ 22.39) before its costs would equal those proposed by the developer. The developer's asking price (~~5.14~~ 5.33 ¢/Kwh) exceeds PPGC's costs (~~4.38~~ 4.35 ¢/Kwh) by ~~17.4%~~ 22.5%.

The remaining two tables on Page 3 demonstrate how equity returns change as a function of both the debt-to-equity ratio and the investor's cost of borrowing debt. The first table shows the results at PPGC's cost of money and the second table shows results at the overall "break-even" cost of capital, which includes the premium necessary to match the proposed project's costs. When interpreting the results shown in these two tables, it is important to keep in mind that these calculations reflect costs to fund PPGC's plant investments, which are usually different from those of the developer. In other words, the equity returns shown could only be earned by the developer if his investment per kilowatt were identical to that calculated for PPGC in first table on this page. If the developer's required investment is greater, then his earned returns will be less than those shown, and vice versa.

Again referring to the generic project, we can observe that, for example, if debt could be obtained at 10% and the financing consisted of 50/50 debt and equity funds, then the equity return would be ~~30%~~ 35 with overall capital costs of ~~20.12%~~ 22.39%.



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### 1.2.4 Page 4 - Auxiliary Computations

This page contains supporting data and computations necessary to the inputs used in Page 1. The first table shows the derivation of the forecast of 1996 prices for coal and gas and the second is the computation of capacity and energy cost proportions used in two of the reference cases.

The 1996 coal and gas price forecasts are derived from the estimates which are being used in the least-cost studies currently underway for PPGC. In the case of coal, the price of standard coal as of February, 1994, of 1.45 $/Gj , excluding transportation, was escalated based on factors from the least-cost study inputs to obtain the estimated 1996 level of 1.52 $/Gj. For gas, the estimated 1995 as-delivered price of 3.51 $/Gj contained in the least-cost data was estimated to reach a level of 3.59 $/Gj in 1996.

The year-to-year data contained in the second table shows the quantities of capacity and energy that would be supplied by coal-fired steam and gas-fired combustion turbines, if the power currently available from CHP plants (capacity factor 64.3%) had to be replaced by generation from power-only plants.

This table is obtained from the output of the GPT model for the twenty-one year period 1996-2016. Since the system currently has a surplus of coal-fired, base load generating plants, it requires many years before a balance between peaking and base units is achieved. Therefore, the proportions of coal and gas plants and energy production vary widely over the study period. For the purposes of this PPAE spreadsheet, which is based on 1996 price levels, a single proportion for both capacity and energy is required which will fairly represent the pattern revealed in the GPT results. Therefore, a present value computation was made to calculate the value of these capacity and energy proportions to PPGC in 1996. It is these results which determine the proportions of capacity and energy used in Page 1 of the PPAE. The results are applied either to the Avoided Cost or Mature System reference cases, as indicated.

### 1.2.5 Page 5 - Reference Case Input Data

The purpose of this page is to permit the analyst to change input parameters for the reference cases to test sensitivities or alternative scenarios of interest. Both numeric and text inputs may be entered, including the names and descriptions of the reference cases. The data contained on this page is generally the same as that used in the GPT analysis of avoided costs. Reasonable variations from these values should produce reliable results; however, larger deviations may require that the GPT model be used to measure any changes to the relative coal and gas proportions which form a critical component of avoided cost results.

### 1.2.6 Page 6 - Summary of Reference Case Analyses

This page summarizes the results of comparing the proposed project to the three reference cases. When the analyst chooses a particular reference case from the spreadsheet menu, summary data is extracted for presentation on this page. If changes to input data are made, each of the reference cases should be selected and run in order to update the information displayed on this page.

The first table presents a comparison of the three reference cases. ~~Both unadjusted reference costs and equalized fixed cost data are shown~~. The average total unit cost per Kwh is calculated at the proposed project load factor in each case. ~~Note that this result is the same for both unadjusted and equalized reference costs. Using the Avoided Cost case as a basis, the cost difference for the Mature System and Similar Project cases is computed.~~

The project costs table compares unit fixed costs for the project to each of the reference cases, both in terms of unit costs and total annual revenues. Project costs are also measured as a percentage of reference costs in each case. For the generic project example, proposed costs would be much greater than system avoided costs, but fall below both Mature System and Similar Project (which in this case is a coal-fired unit, as noted) reference cost levels.

In the cost of capital section, the relative attractiveness of the project is shown in terms of the capital cost premium above (or below) PPGC's cost of money and the total cost of capital which would be required to match the proposed project's costs. As expected, the results for the generic project are consistent with the alignment of relative fixed costs shown in the preceding table.

## 1.3 USE OF THE PPAE SPREADSHEET TO EVALUATE POWER SALES PROPOSALS

In the lower part of Page 1 of the PPAE, next to "Borrowing Cost", is PPGC's fixed cost compared to PPGC's net fixed payment proposed by the project developers, which is obtained from the "Levelized Capacity Payment" calculated on Page 2. A fair power purchase agreement must bring these two numbers together as a result of negotiations that must involve concessions from each side. Page 3 of the PPAE shows how a capital cost premium might be used to accomplish this reconciliation, but it is only one of a number of approaches to contract price negotiation.

The purchaser's concessions may include one or more of the following:

- Modifying inputs to the AC computation to resolve any differences in the perception of power production costs.
- Giving consideration to MC case results which eliminate the impact of system transition to a more balanced system resource mix.
- Taking into account results of the SP case to recognize the higher cost of any single project as compared to the least cost combination of resources.
- Accepting a reasonable and explicit premium as the cost of attracting private investment.
- Assigning value to the opportunity to obtain experience with technologies new to Poland which have the potential to provide significant future benefits.
- Considering the positive "ripple affects" in the greater Polish economy from the stimulus provided by a specific power plant construction project.

The seller's concessions may include:

- Negotiating a lower cost of capital funds or accepting a lower return on investors' equity.
- Reducing the purchase price after the repayment period of any loans or equity investments required for the implementation of the project.
- Re-evaluation of the required investment to accomplish project objectives.
- Reduction of capital costs through ~~the acceptance of more project risk and~~ the reduction of risk premiums included in proposed project prices.

The PPAE offers a simple way of assessing the difference between PPGC's cost estimates and prices proposed by the project developer. It also identifies the magnitude of concessions required to arrive at an agreement between the parties.

With the interest rate premium set to zero, the difference in fixed costs per kw between the reference case and the project estimates is one measure of the net benefits or costs associated with the proposed purchase agreement. This difference is easily converted to annual revenues as shown on Page 3 of the PPAE.



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A second measure of the relative costs of the project is obtained by adjusting the interest rate premium. The premium needed to equalize the fixed costs of the reference case and project fixed costs represents the cost to PPGC of attracting private investment for power generation. It is a measure of the equivalent cost of capital to PPGC of choosing to purchase power from the developer instead of building new capacity using its own, lower cost capital funds. This information may be used to measure the relative expectations of investors concerning their return on investment in Poland as compared to other markets competing for private capital in the power development sector.



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## APPENDIX 2
## GORZOW

This project is designed to provide approximately 50 Mw of electric generating capability and 150 Mw of thermal capacity in a new combined heat and power plant utilizing natural gas as its primary fuel. The proposed plant will be located at the existing Gorzow plant site which has a current capacity of about 67 $Mw_e$ and 350 $Mw_t$. The existing unit one at the Gorzow plant, which is coal-fired, will be retired (except that two of the four old boilers may be converted to gas for standby, heat-only purposes).

A principal project goal is the elimination of the existing unit one, which is the source of serious air pollution problems. The project will also add enough heat capacity to permit the closing of small neighborhood boiler houses used for local district heating which are highly inefficient and also contribute significantly to air pollution. Another goal is to increase the plant's thermal capacity in order to enhance the area's ability to attract new industry. The developers recognize that there is no current need for new electric generating capacity in Poland.

This project is being undertaken by Gorzow Coastal Power Company, S.A. (CPPC), a joint venture between Elektrocieplownia Gorzow and Coastal Power Production Company.

### *Description of the Project*

The project consists of two rehabilitated 18 Mw General Electric Frame 5R combustion gas turbines (owned by Coastal) which will exhaust to two heat recovery steam generators which, in turn, will provide high pressure steam both to an existing 14 Mw steam turbine "T2" (previously abandoned, but to be rehabilitated), and to the local district heating system.

Natural gas will be the primary fuel with distillate oil as a standby for use during emergencies or to supplement gas during peak periods. CPPC intends to negotiate a contract with Zielona Gora Oil & Gas Enterprise for a long term gas supply from a new, low methane gas field near Poznan ("Paproc") delivered to the site by a dedicated pipeline constructed solely for this purpose. The Paproc field is located in western Poland, approximately 75 kilometers southeast of Gorzow.

### *Project-specific Data Used for Analysis*

For economic evaluation purposes, project-specific data has been derived from documents supplied by the developer to PPGC. Further discussion of these data and the original sources relied upon are set forth below.

### *Contract Term*

The contract term is 22 years (1996-2017), as set forth in the Coastal letter of January 14, 1994.

### *Energy Production and Capacity*

Annual energy production of 314,184 Mwh was taken from Exhibit 3 to the Coastal letter dated February 3, 1994, which represents the most recent, revised estimates made available for analysis.

In this analysis capacity is regarded as having value only in association with actual electric energy production, which itself is a by-product of plant operations dedicated to meeting thermal production requirements. The characteristics of the existing block of CHP plants are such that, on average, the relationship between annual energy production and maximum capacity useful to PPGC is represented by a capacity factor of approximately 64.3%. This relationship is used to compute maximum useful capacity, provided, however, that the result cannot exceed the actual maximum net capability of the plant.

In this case, average annual capacity (annual Mwh divided by 8760 hours) is calculated to be 35.9 Mw. Applying the average CHP Block capacity factor of 64.3% yields a maximum useful capacity of 55.8 Mw; however, this exceeds total unit capability (nominally 50 Mw gross rated capacity). Therefore, generating capacity has been calculated as the weighted average of the seasonal net capacity values provided in the attachments to the Coastal letter of 6/23/93. This yields a useful capacity of 44.2 Mw, which has been used in this analysis. Production and capacity are assumed to be constant over the life of the project.

### *Proposed Project Revenues*

Estimates of energy revenues are based on the average price of 1.9 ¢/Kwh contained in Coastal's 2/3/94 letter. Capacity revenues were taken from monthly fixed charges for each contract year as included in Coastal's letter of 1/14/94.

*Sources of Data*

1. Project Feasibility Study, Coastal Power Production Company, October 2, 1992.

2. Letter to Jacek Brandt, PPGC, from Zachariah Allen, Coastal Power Production Company, June 23, 1993.

3. Letter to Jacek Brandt, PPGC, from Christian J. Reinhardt, Coastal Power Production Company, February 3, 1994.

4. Letter to Professor Jan Popczyk, PPGC, from Clark R. Burley, Coastal Power Production Company, February 3, 1994.

5. Letter to Professor Jan Popczyk, PPGC, from Clark R. Burley, Coastal Power Production Company, February 17, 1994.

6. Letter to Christian J. Reinhardt, Coastal Power Production Company, from Jacek Brandt, PPGC, February 25, 1994.

***Results of the Project Evaluation***

The Gorzow project proposal was compared to PPGC's costs of providing the same block of power using three reference cases: Avoided Costs, Mature System and Similar Project. The summary page of the PPAE analysis is included here as Exhibit A2-1 and these results are discussed below.

The cost of power deliveries as per the proposed terms would represent annual costs of $ 8.3 M over PPGC's strict avoided costs and annual costs of $ 5.5 M over PPGC's mature system avoided costs.

If PPGC could raise capital at a real interest rate of 12% then it could develop power from similar technology and fuel for a total cost of 5.22 Cents/kWh against the proposed total sale price of 6.73 Cents/kWh representing additional costs to PPGC of $ 4.75 M per year. If PPGC could not raise capital and this were the only alternative power supply it would represent an equivalent capital cost of 22.62 percent in real terms.

Based on these facts, additional benefits not encompassed within the economic analyses presented here must exist to ensure that ~~total~~ the total value received by PPGC is sufficient to justify the additional costs.



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# EXHIBIT A2-1

PAGE 6

## SUMMARY OF REFERENCE CASE ANALYSES FOR GORZOW

| | | |
|---|---|---|
| USEFUL CAPACITY | 44.2 Mw | 22 YEAR CONTRACT |
| ANNUAL PRODUCTION | 314,184 Mwh | (1996 – 2017) |
| CAPACITY FACTOR | 81.1 % | |

| | | PROPOSED PROJECT* | REFERENCE CASES: AVOIDED COST | MATURE SYSTEM | SIMILAR PROJECT |
|---|---|---|---|---|---|
| **UNIT COSTS** | | | | | |
| FIXED | $/Kw–Yr | 343.45 | 78.53 | 131.33 | 135.30 |
| VARIABLE | ¢/Kwh | 1.90 | 2.99 | 3.12 | 3.32 |
| TOTAL (CF = 81.1%) | ¢/Kwh | 6.73 | 4.10 | 4.97 | 5.22 |
| **ANNUAL REVENUES** | | | | | |
| FIXED | K$ | 15,181 | 3,471 | 5,805 | 5,980 |
| VARIABLE | K$ | 5,969 | 9,398 | 9,817 | 10,418 |
| TOTAL | K$ | 21,150 | 12,869 | 15,622 | 16,398 |
| **OVER/(UNDER) REFERENCE CASE** | | | | | |
| AMOUNT: | | | | | |
| FIXED | K$ | --- | 11,710 | 9,376 | 9,200 |
| VARIABLE | K$ | --- | (3,429) | (3,848) | (4,449) |
| TOTAL | K$ | --- | 8,281 | 5,528 | 4,752 |
| PERCENT: | | | | | |
| FIXED | | --- | 337.4% | 161.5% | 153.8% |
| VARIABLE | | --- | –36.5% | –39.2% | –42.7% |
| TOTAL | | --- | 64.3% | 35.4% | 29.0% |
| **COST OF CAPITAL** | | | | | |
| (PSE COSTS = 12.00%) | | | | | |
| BREAK–EVEN PREMIUM | | --- | 28.17% | 10.47% | 10.62% |
| BREAK–EVEN COST OF MONEY | | --- | 40.17% | 22.47% | 22.62% |

* For purposes of this summary no adjustments have been made to the proposed project unit costs (in each reference case adjustments were made to equalize fuel costs to facilitate a direct comparison of fixed costs).

Note: Similar plant case is based on a gas–fired unit.

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## APPENDIX 3
## CHORZOW

The Chorzow Power Plant is located in Katowice which is in the center of the Upper Selesian Industrial Region, a major urban and industrial area.

The proposed installation of new boilers will permit not only the retirement of existing steam boilers at the station, but also the closing of local district heating boilers, all of which contribute to unacceptable levels of air pollution. Provisions have also been made to meet applicable environmental standards for water and noise pollution and the treatment of furnace waste products.

This project is being developed jointly by the current plant owner, Elektrocieplownia Chorzow ("Elcho") and TransPower, a subsidiary of AES Corporation.

### *Description of the Project*

Modifications proposed for the existing Chorzow plant include the addition of three fluidized-bed coal-fired boilers (type OPF-230) with a gross capacity of 320 $Mw_t$ and three steam turbines (13UCK-65's), each with a rated capacity of 63.4 $Mw_e$. The existing station has a thermal rating of 490 $Mw_t$ and electrical capacity of 100 $Mw_e$. Four existing steam boilers and all of the existing turbine sets will be shut down upon completion of the proposed renovations. Total thermal capacity will increase by 200 $Mw_t$.

Total gross electric capacity is estimated to be 165.6 Mw during heating months (cogeneration mode) and 190 Mw when operating in condensing mode during the summer months.

### *Project-specific Data Used for Analysis*

For economic evaluation purposes, project-specific data has been derived from documents supplied by the developer to PPGC. Further discussion of these data and the original sources relied upon are set forth below.

### *Contract Term*

The contract term is 17 years (1996-2012), as set forth in the economic analysis by Elcho dated 5-11-93 and attached to the Energoprojekt study cited below.

### *Energy Production and Capacity*

Annual energy production is 745,822 Mwh in condensing mode and 489,717 Mwh when cogenerating, for a total yearly output of 1,235,539 Mwh (operations during the first two years are at lower production levels).

In this analysis capacity is regarded as having value only in association with actual electric energy production, which itself is a by-product of plant operations dedicated to meeting thermal production requirements. The characteristics of the existing block of CHP plants are such that, on average, the relationship between annual energy production and maximum capacity useful to PPGC is represented by a capacity factor of approximately 64.3%. This relationship is used to compute maximum useful capacity, provided, however, that the result cannot exceed the actual maximum net capability of the plant.

In this case, average annual capacity (annual Mwh divided by 8760 hours) is calculated to be 141.1 Mw. Applying the average CHP Block capacity factor of 64.3% yields a maximum useful capacity of 219.4 Mw; however, this exceeds total unit capability (nominally rated capacity is 190 Mw gross, 175 Mw net). Therefore, generating capacity has been set equal to 175 Mw for use in this analysis. After the first two years, production and capacity are assumed to be constant over the life of the project.

### *Proposed Project Revenues*

Estimates of energy revenues are based on an average price of 1.52 ¢/Kwh applicable to energy produced in cogeneration mode and 2.43 ¢/Kwh when condensing. Proposed capacity revenues were taken from data included in the Elcho economic analysis.

### *Sources of Data*

1. Reconstruction of Chorzow Power Station - Compendium, Power Engineering Study and Design Office - Energoprojekt, Kotowice, June, 1992.

2. Economic Analysis (Version 5.0), Elcho, May 11, 1993. (Attached as an appendix to the Energoprojekt report cited above)

### *Results of the Project Evaluation*

The Chorzow project proposal was compared to PPGC's costs of providing the same block of power using three reference cases: Avoided Costs, Mature System and Similar Project. The summary page of the PPAE analysis is included here as Exhibit A3-1 and these results are discussed below.



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The cost of power deliveries as per the proposed terms would represent annual costs of $ 20.9 M over PPGC's strict avoided costs and annual costs of $ 10.0 M over PPGC's mature system avoided costs.

If PPGC could raise capital at a real interest rate of 12% then it could develop power from similar technology and fuel for a total cost of 5.2 Cents/kWh against the proposed total sale price of 5.79 Cents/kWh representing additional costs to PPGC of $ 7.2 M per year. If PPGC could not raise capital and this were the only alternative power supply it would represent an equivalent capital cost of 14.13 percent in real terms.

Based on these facts, additional benefits not encompassed within the economic analyses presented here must exist to ensure that total justify the additional costs.



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# EXHIBIT A3-1

PAGE 6 SUMMARY OF REFERENCE CASE ANALYSES FOR CHORZOW

| | | |
|---|---|---|
| USEFUL CAPACITY | 175.0 Mw | 17 YEAR CONTRACT |
| ANNUAL PRODUCTION | 1,235,539 Mwh | (1996 – 2012) |
| CAPACITY FACTOR | 80.6 % | |

| | | PROPOSED PROJECT* | REFERENCE CASES AVOIDED COST | MATURE SYSTEM | SIMILAR PROJECT |
|---|---|---|---|---|---|
| **UNIT COSTS** | | | | | |
| FIXED | $/Kw–Yr | 252.99 | 78.53 | 131.33 | 220.88 |
| VARIABLE | ¢/Kwh | 2.07 | 2.99 | 3.12 | 2.08 |
| TOTAL (CF = 80.6%) | ¢/Kwh | 5.79 | 4.10 | 4.98 | 5.20 |
| **ANNUAL REVENUES** | | | | | |
| FIXED | K$ | 46,024 | 13,742 | 22,983 | 38,655 |
| VARIABLE | K$ | 25,567 | 36,958 | 38,607 | 25,653 |
| TOTAL | K$ | 71,591 | 50,700 | 61,590 | 64,308 |
| **OVER/(UNDER) REFERENCE CASE** | | | | | |
| AMOUNT: | | | | | |
| FIXED | K$ | --- | 32,282 | 23,041 | 7,369 |
| VARIABLE | K$ | --- | (11,391) | (13,040) | (86) |
| TOTAL | K$ | --- | 20,891 | 10,001 | 7,283 |
| PERCENT: | | | | | |
| FIXED | | --- | 234.9% | 100.3% | 19.1% |
| VARIABLE | | --- | –30.8% | –33.8% | –0.3% |
| TOTAL | | --- | 41.2% | 16.2% | 11.3% |
| **COST OF CAPITAL** | | | | | |
| (PSE COSTS = 12.00%) | | | | | |
| BREAK–EVEN PREMIUM | | --- | 20.92% | 6.17% | 2.13% |
| BREAK–EVEN COST OF MONEY | | --- | 32.92% | 18.17% | 14.13% |

* For purposes of this summary no adjustments have been made to the proposed project unit costs (in each reference case adjustments were made to equalize fuel costs to facilitate a direct comparison of fixed costs).

Note: Similar plant case is based on a coal–fired unit.

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## APPENDIX 4
## KRAKOV LEG

Krakov Leg (Elektrocieplownia Leg) is one of the two major CHP plants located in and around Krakov. It is located close to the center of the city on the banks of the Vistula River with an installed capacity of 454 $Mw_e$ and 1,404 $Mw_t$. Each year the plant burns over 1 million tons of hard coal obtained from mines located in the vicinity of Katowich in Upper Silesia.

The pressing need to improve air quality is the prime motivation for this proposal, just as it is for the other projects presented to PPGC. Initially, plans call for rehabilitation of existing boilers, adding emissions controls and other system improvements. Additional capacity is scheduled for installation beginning in 1997. Fluidized bed combustion technology may be utilized if it is sufficiently advanced enough to limit the technology risks to acceptable levels at that time.

This project is being developed by the current plant owner/operators and United Energy Partners, a partnership formed for the purpose of developing and operating environmental and energy projects in Poland. The five partners are all subsidiaries of major U.S. corporations, including two investor-owned energy utilities, two power industry equipment suppliers and a diversified railroad transportation and financial services company.

### *Description of the Project*

The existing configuration of the plant consists of four cogeneration units. Units 1 and 2 with a rated capacity of 120 $Mw_e$ each are designated BC-90 and are designed to operate either as topping or condensing units. During the heating season steam can be extracted from the turbines to heat hot water used for district heating purposes. The remaining two units, designated as BC-100, are rated at 107 $Mw_e$ apiece and operate in topping mode only, since they are not equipped with condensers. However, even when there is no heat demand these units generate some electricity by circulating cooling water through the units' low pressure feedwater heaters which are normally used to exchange heat with the district heating system.

Available electric capacity is substantially less than nominal rated gross capacity of 454 Mw when these units are utilized to produce heat.

### *Project-specific Data Used for Analysis*

For economic evaluation purposes, project-specific data has been derived from documents supplied by the developer to PPGC. Further discussion of these data and the original sources relied upon are set forth below.

### *Contract Term*

The contract term is 20 years (1996-2015), as set forth in the economic analysis by United Energy Partners dated 8-23-91.

### *Energy Production and Capacity*

Annual energy production is estimated to be 1,628 Gwh in 1996 and is projected to grow at an annual rate of about 2% annually over the contract term. This growth in production is unique among the four projects evaluated and appears to occur in conjunction with an anticipated growth in heat sales to the district heating system as small local heating boilers, which are both inefficient and heavy contributors to the city's severe air pollution problems, are removed from service over time. Where the PPAE spreadsheet requires a single value for production in certain computations, the average production amount, 1,978 Gwh, over the life of the contract is used.

In this analysis capacity is regarded as having value only in association with actual electric energy production, which itself is a by-product of plant operations dedicated to meeting thermal production requirements. The characteristics of the existing block of CHP plants are such that, on average, the relationship between annual energy production and maximum capacity useful to PPGC is represented by a capacity factor of approximately 64.3%. This relationship is used to compute maximum useful capacity, provided, however, that the result cannot exceed the actual maximum net capability of the plant.

Following the procedure used in other cases, the average annual capacity (annual Mwh divided by 8760 hours) is calculated to be 225.8 Mw using the annual average production over the contract term. Applying the average CHP Block capacity factor of 64.3% yields a maximum useful capacity of 351.2 Mw. However, comparing this result to data supplied by the developer produces a lower useful capacity value. The total gross capability of the unit available for electricity production is 363 Mw according to the developer's economic study (total rated capacity is 454 Mw gross). Using this data, net available capacity has been estimated to be 334 Mw (92% of gross) for this analysis.

### *Proposed Project Revenues*

Both fixed charge revenues and energy prices are provided on page 35 of the study dated 8-23-91. These data are reflected in this analysis, except that the energy price of 2.26 ¢/Kwh in 1996 has been held constant over the life of the contract instead of using the original, escalated values. This constant energy price approach has been used throughout the analyses of all projects to eliminate any differences in assumptions about future fuel prices which might otherwise cloud the results. It is anticipated that the contract terms used to adjust prices for changes in future fuel costs would not have a material impact on the economic comparisons used for this analysis.

### *Results of the Project Evaluation*

The Krakov Leg project proposal was compared to PPGC's costs of providing the same block of power using three reference cases: Avoided Costs, Mature System and Similar Project. Detailed results are presented in the associated appendix. The summary page of the PPAE analysis is included here as Exhibit A4-1 and these results are discussed below.

22.0 The cost of power deliveries as per the proposed terms would represent annual costs of $ ~~23.67~~ M over PPGC's strict avoided costs and annual costs of ~~$ 3.68~~ 1.8 M over PPGC's mature system avoided costs.

If PPGC could raise capital at a real interest rate of 12% then it could develop power from similar technology and fuel for a total cost of 5.8 Cents/kWh against the proposed total sale price of 5.43 Cents/kWh representing savings of ~~$ 7.75~~ 2.4 M per year. If PPGC could not raise capital and this were the only alternative power supply it would represent an equivalent capital cost of 10.75 percent in real terms.

While costs of this project exceed "strict" avoided costs substantially, this analysis shows that if the system were in a balanced condition, this project would warrant further detailed analysis and negotiation with the developers (particularly since the changing annual production amounts have been averaged here). Except for the fact that there is a substantial imbalance in the system which continues for many years to come, this project has the potential to provide power at a price which would reflect its value to PPGC. The results of the Similar Project case simply confirm the relative attractiveness of this project compared to some of the others analyzed.

# EXHIBIT A4-1

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## SUMMARY OF REFERENCE CASE ANALYSES FOR KRAKOV LEG

| | | |
|---|---|---|
| USEFUL CAPACITY | 334.0 Mw | 20 YEAR CONTRACT |
| ANNUAL PRODUCTION | 1,762,000 Mwh | (1996 – 2015) |
| CAPACITY FACTOR | 67.6 % | |

| | | | PROPOSED PROJECT* | REFERENCE CASES: AVOIDED COST | MATURE SYSTEM | SIMILAR PROJECT |
|---|---|---|---|---|---|---|
| **UNIT COSTS** | | | | | | |
| FIXED | | $/Kw–Yr | 188.05 | 78.53 | 131.33 | 220.88 |
| VARIABLE | | ¢/Kwh | 2.26 | 2.99 | 3.12 | 2.08 |
| TOTAL | (CF = 67.6%) | ¢/Kwh | 5.43 | 4.32 | 5.34 | 5.81 |
| **ANNUAL REVENUES** | | | | | | |
| FIXED | | K$ | 62,810 | 26,229 | 43,865 | 73,775 |
| VARIABLE | | K$ | 39,795 | 52,706 | 55,058 | 36,584 |
| TOTAL | | K$ | 102,606 | 78,934 | 98,923 | 110,359 |
| **OVER/(UNDER) REFERENCE CASE** | | | | | | |
| AMOUNT: | | | | | | |
| FIXED | | K$ | --- | 36,582 | 18,945 | (10,965) |
| VARIABLE | | K$ | --- | (12,910) | (15,262) | 3,211 |
| TOTAL | | K$ | --- | 23,671 | 3,683 | (7,754) |
| PERCENT: | | | | | | |
| FIXED | | | --- | 139.5% | 43.2% | –14.9% |
| VARIABLE | | | --- | –24.5% | –27.7% | 8.8% |
| TOTAL | | | --- | 30.0% | 3.7% | –7.0% |
| **COST OF CAPITAL** | | | | | | |
| (PSE COSTS = 12.00%) | | | | | | |
| BREAK–EVEN PREMIUM | | | --- | 12.28% | 0.85% | –1.25% |
| BREAK–EVEN COST OF MONEY | | | --- | 24.28% | 12.85% | 10.75% |

* For purposes of this summary no adjustments have been made to the proposed project unit costs (in each reference case adjustments were made to equalize fuel costs to facilitate a direct comparison of fixed costs).

Note: Similar plant case is based on a coal–fired unit.

## APPENDIX 5
## BIELSKO-BIALA

The Bielsko-Biala project represents the third stage of development of power plant facilities serving the Bielsko area. Two new units of 55 $Mw_e$ will be located alongside existing facilities.

The proposed installation of new fluidized bed boilers will permit the retirement of existing steam boilers at the station which are at the end of their service lives and also cannot meet current environmental standards. This project will also meet estimated industrial thermal demand growth and permit the closing of local district heating boilers which contribute heavily to unacceptable levels of air pollution. Provisions have also been made to meet applicable environmental standards for water and noise pollution and the treatment of furnace waste products.

This project is being developed by ZEC Bielsko-Biala, the group of heat distribution companies in Bielsko, who anticipate a joint effort with other partners to secure the necessary financing and otherwise contribute to the success of this enterprise.

### *Description of the Project*

Modifications proposed for the existing Bielsko-Biala plant include the addition of two thermal-electric BC-50 units, designated CHP1 and CHP2, consisting of an extraction, back-pressure steam turbine (type 13 UP-55) with a nameplate rating of 55 $MW_e$ and a circulating, fluidized-bed, coal-fired boiler (type OFZ-230) with a gross capacity of 104 $Mw_t$. The existing station has a thermal rating of 393 $Mw_t$ and no electric power production capability.

Total gross electric capacity is 111 Mw, but the useful capacity to PPGC is expected to be somewhat less due to the limitations imposed by cogeneration operations.

### *Project-Specific Data Used for Analysis*

For economic evaluation purposes, project-specific data has been derived from documents supplied by the developer to PPGC. Further discussion of these data and the original sources relied upon are set forth below.

### *Contract Term*

The contract term is 17 years (1996-2012), as set forth in the Electroprojekt economic analysis included in its study dated June 1992.

### *Energy Production and Capacity*

Annual energy production estimates are taken from the analysis cited as reference 2 below. Production during the first four years varies and then becomes constant at 596,400 Mwh for the remainder of the contract term. This figure is used where a single production value is required in the PPAE analysis.

In this analysis capacity is regarded as having value only in association with actual electric energy production, which itself is a by-product of plant operations dedicated to meeting thermal production requirements. The characteristics of the existing block of CHP plants are such that, on average, the relationship between annual energy production and maximum capacity useful to PPGC is represented by a capacity factor of approximately 64.3%. This relationship is used to compute maximum useful capacity, provided, however, that the result cannot exceed the actual maximum net capability of the plant.

Following the procedure used in other cases, the average annual capacity (annual Mwh divided by 8760 hours) is calculated to be 68.1 Mw using the annual average production over the contract term. Applying the average CHP Block capacity factor of 64.3% yields a maximum useful capacity of 105.9 Mw. However, since the total gross capability of the unit available for electricity production is only 111 Mw, net available capacity has been estimated to be 102 Mw (92% of gross) for this analysis.

### *Proposed Project Revenues*

No breakdown between fixed charges and energy prices is provided in the data available for review. For this analysis, energy prices were set equal to the energy price of the Similar Unit reference case (a coal-fired steam turbine) at 2.08 ¢/Kwh. Because the level of total revenues in the study is very low, a further adjustment was made to increase the original total revenues from 1993 to 1996 price levels. The revised revenue level was computed by increasing the original data by 4% per year for three years. As shown below, the proposed revenues are still very favorable to PPGC.

### *Sources of Data*

1. Extension of the Bielsko-North Thermal-Electric Power Station II - New Power Unit BC-50 - Feasibility Study, Power Engineering Study and Design Office - Energoprojekt, Kotowice, June, 1992.

2. Updated economic analysis worksheets provided by PPGC to Hagler Bailly, February, 1994.

***Results of the Project Evaluation***

The Bielsko-Biala project proposal was compared to PPGC's costs of providing the same block of power using three reference cases: Avoided Costs, Mature System and Similar Project. Detailed results are presented in the associated appendix. The summary page of the PPAE analysis is included here as Exhibit A5-1 and these results are discussed below.

The cost of power deliveries as per the proposed terms would represent annual savings of ~~$ 2.33~~ 2.6 M over PPGC's strict avoided costs and annual savings of ~~$ 8.51~~ 8.7 M over PPGC's mature system avoided costs.

If PPGC could raise capital at a real interest rate of 12% then it could develop power from similar technology and fuel for a total cost of 5.85 Cents/kWh against the proposed total sale price of ~~3.94~~ 3.91 Cents/kWh representing savings of ~~$ 11.39~~ 11.6 M per year. If PPGC could not raise capital and this were the only alternative power supply it would represent an equivalent capital cost of 4.56 percent in real terms.

These results suggest that this project should be vigorously pursued with detailed analyses to verify these preliminary conclusions and begin negotiation of a definitive purchased power agreement.