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Preface

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ENER Forum 2

Monitoring the progress of the implementation of the EU Gas and Electricity Directives: Are European markets becoming competitive?

Prague, Czech Republic, 15-16 November 2001

The European Network for Energy Economics Research

Thematic Network of the European Union Fifth Framework Programme (ENERGIE)

May 2002

The European Network for Energy Economics Research (ENER).

Thematic Network of the European Union Fifth Framework Programme (ENERGIE)

ENER Forum 2: Monitoring the progress of the implementation of the EU Gas and Electricity Directives: Are European markets becoming competitive? Prague, Czech Republic, 15-16 November 2001

Abstract

The objective of the 2nd Forum of the European Network for Energy Economics Research ENER is to stimulate the discussion and exchange of knowledge on the progress, barriers, difficulties and prospects of the implementation of the EU Electricity and Gas Directives, among relevant stakeholders, such as governments, energy companies, regulators, TSOs and consumers, in EU and Accession countries.

The Forum meetings also aim at strengthening the links between national centres in energy/environmental policy and economics research, in particular with those in Accession countries. In total four Forums will be held on different topics that are relevant for the EU. The Thematic Network project ENER, co-ordinated by FhG-ISI, brings together sixteen institutes from different EU Member States, Candidate countries and Switzerland.

The Bulletin presents the results of the discussions in the following sessions:

- Session 1: The Internal Electricity Market: Implementation of the EU Directives
- Session 2: Implementation of the electricity market liberalisation in the EU accession countries
- Session 3: Implementation of gas directive
- Session 4: Green and clean electricity

Cover

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The European Network for Energy Economics Research (ENER)

Energy policies, traditionally national preserves, have become increasingly determined in international areas, and nowhere more so than in the European Union. In view of these movements towards more international and more environmentally responsive energy policies, researchers from IEFE (Institute of Energy Economics, Bocconi University, Milan), IEPE (Institute of Energy Policy and Economics, University of Grenoble), and SPRU (Science and Technology Policy Research, University of Sussex) made a cooperation agreement in September 1985 to promote better communication among the groups and stimulate joint research activities. Since then the activities of the Network have been financially supported by the European Commission's Directorates General for Energy and for Research.

ENER has since then grown to include FhG/ISI (Fraunhofer Institute of Systems and Innovation Research, Karlsruhe) in 1988, CEEETA (Centre for the Economic Study of Energy, Transport and the Environment, Lisbon) in 1989, GIEE (Inter University Group on Energy Studies, Madrid) in 1992. In 1995, the Systems Analysis Department of Risø National Laboratory, Roskilde, the Policy Study Unit of the Netherlands Energy Research Foundation (ECN), Petten, and the Study Centre on Technology, Energy and Environment (STEM, University of Antwerpen) joined the network. Lund University, Department of Environmental and Energy System Studies became a member in 1996, the Institute of Energy Economics at the Vienna Technical University (IEW) in 1997.

With the current series of Forums the ENER Network is opening up to the accession countries with participants from Poland (Polish Foundation for Energy Efficiency FEWE Center in Krakow / University of Mining and Metallurgy UMM), Czech Republic (SRC International CS), Hungary (Energia Klub), Romania (Institute of Power Studies and Design ISPE) and to Switzerland (Centre for Energy Policy and Economics CEPE).

Preface

The objective of the Forum of the European Network for Energy Economics Research ENER is to create a debate between relevant stakeholders in academia, governments, industry and NGOs in important fields in relation to energy, climate change and economics. It also aims at strengthening the links between national centres in energy/environment policy and economics research in particular with Central and Eastern European countries in view of their accession to the EU. It is hoped that the common activities with the partner institutes in those countries as well as with stakeholders participating in the events organised by ENER will contribute to continued co-operation in the same way as the one initiated among ENER institutes in the current EU Member States one decade ago.

For this purpose, a Thematic Network was set up, financially supported by DG Research under the ENERGIE Programme. The Thematic Network co-ordinated by the Fraunhofer Institute for Systems and Innovation Research FhG-ISI/Germany gathers 16 institutes from EU Member Countries, Central and Eastern European Accession Countries and Switzerland, which bring in their skills and experiences in both qualitative and model-based analyses. Within the Thematic Network, four ENER Forums are to be held, all of which in the EU accession countries, under the common theme of *Paths for Energy Policy between Policy Challenges and Market Domination*.

The first ENER Forum 1 was held in Krakow, Poland, February 2001 on the topic *Integrating the Kyoto Mechanisms into the National Framework.* The proceedings of the ENER Forum 1 can be found in the previous ENER Bulletin.

The current ENER Bulletin contains the proceedings of the ENER Forum 2 held in Prague, the Czech Republic, November 2001 on the topic *Monitoring the progress of the implementation of the EU Gas and Electricity Directives: Are European markets becoming competitive?*

The Electricity Directive 96/92/EC has been an important stimulus for significant market and regulatory dynamics that are still unfolding across greater Europe. Electricity production in the EU has for decades been based on monopoly production and 15 separate, national markets. Over time, and due largely to technological change, it became increasingly clear that it was possible to permit competition to develop in this industry, like any other, whilst still maintaining essential and basic public policy and service objectives. Some countries, for example the United Kingdom and much of Scandinavian, made this change some years ago. For most EU countries, however, and for the EU as a whole, the Directive's implementation deadline of 19 February 1999 marks the date that a competitive regulatory framework becomes the norm, not the exception, for electricity trade and production across the EU.

Opening up electricity production to competition is an important tool to improve the efficiency of the electricity production industry and thereby to benefit electricity consumers. This is of fundamental importance given the climate change commitments, given the climate change commitments, which the EU entered into at Kyoto[1].

Likewise, for the European gas sector, the implementation date of 10 August 2000 for the Gas Directive 98/30/EC is a milestone in what has been a very long process of creating a single market for natural gas. Customer choice is the key in opening up European gas markets to competition as it will allow consumers to look for lower prices and better service. New entrants into the gas market will provide new opportunities to the advantage of customers.

Liberalisation of the gas markets is a very important tool that contributes to the development of the European economy towards its goals of efficiency and competitiveness in an ever-increasing global market place[2] .

The objective of the ENER Forum 2 has been to stimulate the discussion and exchange of knowledge on the progress, barriers, difficulties and prospects of the implementation of the EU Electricity and Gas Directives, among relevant stakeholders, such as governments, energy companies, regulators, TSOs and consumers, in EU Member and EU Accession Countries.

In three sessions, the participants addressed a range of issues related to the implementation of EU Electricity and Gas directives in the EU Member States and Accession Countries. In addition, in a fourth session, they discussed green and clean electricity issues in the context of the energy market opening.

The ENER Bulletin provides the text of most of papers presented during the two days of the ENER Forum 2 and also the summaries and major conclusions from the individual sessions. All presentations are available in PowerPoint from the ENER Internet site: www.eu.fhg.de/ENER/Enerhome.htm

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1 Opening to choice: The single electricity market. Luxembourg: Eur-OP, 2000, 22 p.

2 Opening up to Choice: The Single Electricity Market. Luxembourg: Eur-OP, 1999. 21 p.

Opening speeches

Opening of the ENER Forum 2

Jan Pouček, Head of Energy Policy Department, Ministry of Industry and Trade, the Czech Republic

Ladies and Gentlemen,

It is my great pleasure to welcome you to Prague and to open the second ENER Forum on behalf of the Ministry of Industry and Trade of the Czech Republic on also to welcome you in premises of our Ministry.

The Czech Republic, on its process of accession to the European Union, welcomes and appreciates possibilities for further and deeper co-operation with the European Commission, institutions and organisations both from the EU countries and from other accession countries.

The energy sector plays a very important role in national economies of these countries, in their foreign trade, and also in international co-operation and globalisation. The European Commission in its Green Paper of 2000 expressed its concern about the security of energy supply, which becomes even more serious after the incident of the 11 September in the United States.

The European Network for Energy Economics Research, with its 17-year old history and experience, is an important link in this process. We appreciate that the ENER Network has been opened to participation of institutions from accession countries, and it is a great honour for us that Prague has been chosen for organising the second ENER Forum meeting with so important topic as the progress of an implementation of the EU Gas and Electricity Directives.

I would like to use this opportunity and present you a brief review of the progress the Czech Republic has reached in the field of modern energy policy implementation and liberalisation of the energy market.

The Czech Energy Policy was approved by the Government in January 2000. The policy is based on the same objectives as the energy policy of the EU. It emphasises the requirement for security of energy supply, protection of the environment while respecting the principles of sustainable development and also support to the competitiveness of the national economy.

The main strategic objective of our Energy Policy is the determination of the basic concept of the long-term development of the energy sector and specification of necessary legislative, institutional and economic frameworks that would motivate energy companies to introduce the environment-friendly behaviour.

At present, when the current Energy Policy had been in power for nearly 2 years, our Ministry prepared the first monitoring paper. The review of the individual steps made in last 2 years shows that we are on the right track to meeting major targets and indicators. There is no need for making changes in the valid energy policy.

What could be underlined is the fact that we had succeeded to prepare 2 new fundamental acts related to the energy sector that were approved by the Czech Parliament last year and that have been in full power since January 2001. The Energy Act and the Energy Management Act and Decrees and Regulations issued to these acts are in full concordance with the valid EU legislation in this field.

I call your attention especially to the issue of the energy market liberalisation, the main theme of this Forum.

The Czech Energy Act states that natural persons and corporate bodies may do business on the territory of the Czech Republic only on the basis of the state's consent, which is a licence issued by the Energy Regulatory Office. The licence is issued for a period of at least 25 years for generation of electricity and production/import of gas, transmission of electricity and gas, distribution of electricity and gas, storage of gas, production and distribution of heat. In addition, licences are also issued for trade in electricity and gas for a period for at least 5 years.

The Act, furthermore, stipulates detailed terms for the issuance of licences, the position and responsibility of the responsible representative, requirements for the application of a licence, the procedure of the Energy Regulation Office during the issuance of a licence, the rights and obligations of licence holders and the obligation to supply beyond the framework of the licence, including a possible related proven losses and the fund established to cover such losses.

For selected kinds of investments the Energy Act introduced a state authorisation. It concerns construction of power generation units with output of 30 MW and more, construction of direct electricity lines, direct gas pipelines, underground gas reservoirs, gas pipelines connecting the inland gas network with foreign gas systems, selected gas pipelines and heat production units with the total thermal output of 30 MW and more. The Ministry of Industry and Trade decides about the issuance, change, prolongation and cancellation of the state authorisation for construction. Authorisations are issued for corporate bodies and natural persons if they demonstrate their compliance with the conditions stated in the Energy Act.

I would like to emphasise that the Energy Act is entirely non-discriminatory towards foreign persons – they have the same rights and obligations as domestic ones.

Regarding the opening of the energy market, the start of the opening and its speed differs by sector. The market for coal and coal products, as well as for all types of oil products, has been opened some years ago, and the prices of these products are fully driven by the market and are not regulated.

In case of the electricity market, the Energy Act stipulates the position, rights and obligations of electricity market participants, i.e. operator of transmission system, operators of distribution systems, technical dispatch centers, electricity market operator, eligible and protected customers and electricity traders.

The Energy Act stipulates (§ 21) that opening of the market on the territory of the Czech Republic will be organised on the basis of regulated access to the transmission system and the distribution systems and the possibility to construct electricity generation units and direct lines on the basis of the state authorisation. Prices for transmission and distribution of electricity, system services and for protected customers will be regulated by the Energy Regulation Office.

The electricity market will be opened gradually as follows:

- From 1 January 2002 the electricity market will be opened to end users whose consumption of electricity related to one consumption place, including generation for their own consumption, exceeds 40 GWh either in 2000 or in the period from 1 July 2000 to 30 June 2001; the right for regulated access to networks will be also granted to licence holders for generation of electricity with the installed capacity more than 10 MW;
- From 1 January 2003 the electricity market will be opened to end users whose consumption of electricity related to one consumption place, including generation for their own consumption, exceeds 9 GWh in 2001 or in the period from 1 July 2001 to 30 June 2002; the right for regulated access to networks will also be granted to all licence holders for generation of electricity;
- From 1 January 2005 the electricity market will be opened to all end users of electricity supplied from higher than low voltage networks whose consumption related to one consumption place, including generation for their own consumption, exceeds 100 MWh in 2003 or in the period from 1 July 2003 to 30 June 2004; and finally
- From 1 January 2006 the electricity market will be opened to all end users.

Additional procedures of privatisation of the electricity sector were approved by the Czech Government in October 2000. The privatisation consultant has been chosen to help the Government in preparation of the tender and evaluation of the offers. At present, the process of privatisation is ongoing.

Opening of the gas market has also been prepared. The Energy Act stipulates that opening of the market on the territory of the Czech Republic is organised on the basis of agreed access to the transmission system and regulated access to distribution systems and on the basis of authorised access to the construction of selected gas facilities. The gas market will be opened gradually as follows:

- From 1 January 2005 the gas market will be opened within the scope of at least 28% of the total annual consumption of gas in the Czech Republic. The right to selection of the gas supplier will have those licence holders that use gas for generation of electricity in thermal power plants or for co-generation within the scope of their consumption for such generation, eligible customers and licence holders for distribution of gas within the scope stated in the implementing regulation, however, as a minimum eligible customers whose purchase of gas in the previous calendar year measured in one consumption place is higher than 15 million m^3;
- From 10 August 2008 the gas market will be opened within the scope of 33% of the total annual consumption of gas in the Czech Republic. The right to select the gas supplier will have those licence holders that use gas for generation of electricity in thermal power plants or for co-generation within the scope of their consumption for such generation, eligible customers and licence holders for distribution of gas within the scope stated in the implementing legal regulation, however, as a minimum eligible customers whose purchase of gas in the previous calendar year measured in one consumption place is higher than 5 million m^3.

The furtherance of the privatisation of the gas sector was approved by the Government of the Czech Republic in November 2000. The privatisation consultant was selected which is helping the Government in preparation of the tender and in evaluation of individual offers. As in case of the power sector, the process of gas sector privatisation is also ongoing at present.

I would like to inform you that the new Czech energy legislation divides the responsibilities for the exercise of public administration between various public authority bodies. The Ministry of Industry and Trade is mainly involved in development of the energy policy, in issuing the state authorisation for building new energy facilities and for fulfilment of the obligations resulting from the international agreements and treaties. The Energy Regulatory Office was established as a fully independent authority to exercise the regulation in the energy (i.e., power and gas) sectors. The State Energy Inspection Board is supervising whether activities in energy sector are fulfilled in accordance with provisions of the Energy Act and the Energy Management Act and relevant orders.

During this year the necessary Orders of the Ministry of the Industry and Trade and the Energy Regulatory Office as well as Regulations of Government have being issued for the proper implementation of provisions of the new energy acts. Simultaneously the necessary organisational changes and setting new institutional framework has been done.

At present, we are sure that the preparation of our energy sector and public administration is successfully completed for opening the electricity market from the beginning of the next year.

Simultaneously, we have done plenty of work to adapt the whole Czech legislation in such a way that it complies with the EU legislation in this field. We hope that within the negotiation on our accession to the EU, the energy chapter will be successfully closed before the end of current year.

In my opinion, there can be a simple answer to the fundamental question – Is the Czech energy market becoming competitive in compliance with the EU Electricity and Gas Directives? – we can answer:

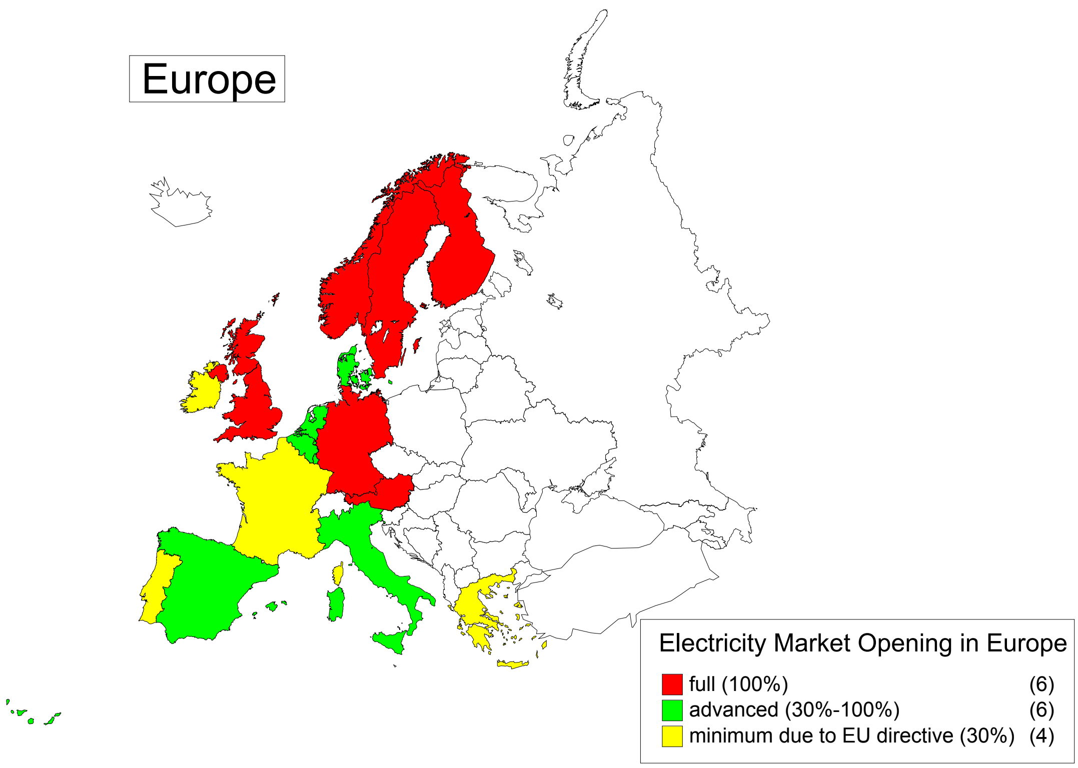
- YES, the market is fully competitive in case of coal and oil products and heat,
- YES, the market will step by step become competitive starting since 2002 in case of electricity; and
- YES, the market will step by step become competitive starting 2005 in case of gas.

Ladies and Gentlemen,

We believe that the ENER Forum in Prague will be very helpful and useful in transferring know-how in issues connected with competitiveness of the energy markets. We are sure that exchange of meanings and experiences among distinguish participants of the Forum could facilitate the wider and faster opening of energy markets. We are looking forward to hearing new ideas and recommendations that will help us solving or overcoming some issues related to this matter.

I wish all of you a successful meeting and pleasant stay in Prague.

Market opening in EU countries, Norway and Switzerland as of 1 January 2002



From Haas and Auer, *Introducing competition in the Western European electricity market: A critical review*, Fig. 1

European Research Area: scientific basis for EU decision-making: The case of energy and environment policies

Domenico Rossetti di Valdalbero, European Commission, DG Research[3]

Keywords. European Research Area, Energy socio-economic research, European policy-making.

Abstract. The European decisions in the field of energy and environment need to have a scientific reference. The methods and tools (models) developed in the EU energy socio-economic research, particularly in the 5th EU RTD Framework Programme, provide the support to many decisions related to energy security of supply, greenhouse gas emission trading within the EU, internalisation of external costs, renewables targets and energy taxation.

Introduction

European decision-makers often tend to support their choices on a scientific base. Whether it is a renewable electricity target, an energy tax, a quantified objective to reduce greenhouse gases emissions, a voluntary agreement between public authorities and industries, a state aid exception for clean energies or a standard for energy efficiency, an evaluation of the impacts of the adopted measure will be requested by policy-makers.

The Communications Towards a European Research Area[4], Making a reality of the ERA: guidelines for EU research activities (2002-2006)[5] and the Amended proposals concerning the specific programmes implementing the 6th FP for RTD&D activities[6] respectively insist on "Developing the research needed for political decisions…", "Support for policy-making and European scientific reference system…" and "Underpin the formulation and implementation of Community policies…".

The EU energy socio-economic research

In the 5th EU RTD&D FP, together with "technological" research which includes hundreds of projects aiming at promoting new and clean energy and environment technologies, improving quality of life, boosting growth, competitiveness and employment, "socio-economic research" in the *Energy, Environment and Sustainable Development* programme provides the scientific basis for energy and environment-related policy formulation. In particular, for the energy part by:

- The elaboration of scenarios for energy supply and demand technologies and their interaction, and the analysis of cost effectiveness (based on full life cycle costs) and efficiency of all energy sources;
- The socio-economic aspects related to energy within the perspective of sustainable development (the impact on society, the economy and employment).

The majority of EU energy socio-economic research projects makes the links between energy and environment and addresses the issues of natural resources, economic growth and social needs including both market competition and environmental constraints, top-down and bottom-up approaches.

The research tools and their policy applications

Some examples of tools and assessment methods developed by EU researchers and used for European policy-making (Energy, Environment, Competition and Taxation) could be presented. This was particularly the case with the projects related to:

- POLES and PRIMES, a world and European energy model that have been and are being considered as part of the scientific references for the:
  - * Energy projections (2020 and 2030) and the impacts of fuel taxation on technology in the Green paper on energy security of supply7;
  - * Economic effects of a EU-wide emission trading in the Proposal for a directive establishing a scheme for greenhouse gas emission allowance trading within the Community8;
  - * World energy, technology and climate outlook – 2030 that will be published by the European Commission at the end of 2002.
- ExternE, a green accounting framework giving the monetary valuation of the socio-environmental damages for the electricity (and partly for transport) fuels and technologies. If various recent EU documents like the *Sixth Environment Action Programme*[9] or the *White Paper on European transport policy for 2010*[10] clearly insist on the need to internalise external costs, *the Community guidelines on State aid for environmental protection*[11] give a concrete figure for a specific case: "*Member States may grant operating aid to new plants producing renewable energy that will be calculated on the basis of the external costs avoided (...). At any event, the*

[3] The views presented in this paper do not necessarily reflect the European Commission official positions and the author alone assume the responsibility for the contents.

[4] COM(2000)6

[5] COM(2000)612

[6] COM(2002)43

[7] COM(2000)769

[8] COM(2001)581

9 COM (2001)31

10 COM (2001)370

11 OJEC, C 37 (3/2/2001)

amount of the aid thus granted to the renewable energy producer must not exceed 5 Euro cents per kWh".

- SAFIRE, a computer based framework providing an indication for setting national targets for electricity from renewable energy sources (the objective is to double –from 6 to 12%- the share of renewables in the gross inland energy consumption, i.e. to pass from 14% today to 22% in 2010 of the electricity produced from renewables). These assessments were used for the *White Paper on renewable sources of energy*[12], for the *Proposal for a directive*[13] and finally for the *Directive on the promotion of electricity produced from renewable energy sources in the internal electricity market*[14].
- GEM–E3, a general equilibrium model which has already given the evaluation of the economic and environmental impacts of energy taxation (cf. *Proposal for a directive restructuring the Community framework for the taxation of energy products*[15]). GEM-E3 could provide future indications on the economic and environmental impacts of the changes, which an introduction of a more harmonised tax regime at the EU level would entail, and the consequences of an internalisation of external costs as mentioned in the *EU strategy for Sustainable Development*[16].

Conclusions

Various recent European documents mention the need of research for policy-making. The 6th EU RTD&D FP in preparation expects to have specific activities covering a wider field of research including the part dedicated to "Supporting policies and anticipating scientific and technological needs" (570 M€ for the 2002-2006 period).

Energy and environment are not the only covered policies but they are key issues in the EU agenda, particularly considering the focus on sustainable development (cf. Göteborg European Council, 15 and 16 June 2001) and the importance of energy at the Barcelona summit (15 and 16 February 2002).

Many quantitative tools have been developed in the past thanks to the European research (non nuclear energy programme). For the future, European policy-makers need to have updated and improved European and world models (endogenous technological change, other Kyoto greenhouse gases, demand side, Central and Eastern European Countries…). New energy systems should be built to take into consideration very-long term problems such as resource depletion, climate change and radioactive waste management. Emerging subjects like the externalities of energy security of supply, the evaluation of ecosystem damages (cf. environmental liability); the sustainable development (cf. Johannesburg); the regional impacts of infrastructure changes (cf. hydrogen economy) or the assessment of a "Kyoto II" should be covered by European research.

Glossary

ERA	European Research Area
EU	European Union
FP	Framework Programme
RTD&D	Research, Technological Development and Demonstration

12 COM(97)599

13 COM (2000)279

14 OJEC, L 283 (27/10/2001)

15 COM(97)30

16 COM(2001)264

Session 1: The Internal Electricity Market: Implementation of the EU Directives

Rapporteur's Summary by Eugene D. Cross, ECN Policy Studies, The Netherlands

Session One was comprised of four presentations and related discussions on the broad theme of the development of the European electricity market in light of the Commission's proposals to amend the existing Electricity and Gas Directives.[17] The underlying effort was to gain a more definitive assessment of the consequences of the liberalisation in the electricity sector and to identify topics for further inquiry. Following the two initial presentations of the relevant views of European Commission and of Eurelectric, a lively debate was stimulated by the critical review offered by Hans Auer and Richard Haas of the Vienna University of Technology. The session was capped nicely by an useful presentation by Clemens Cremer (FhG-ISI) of the options and potentials for cross-border electricity transfers.

The session took a pan-European perspective, for the most part, and it was open-ended in the sense that it formed a basis for subsequent discussions in the afternoon (on national implementation in the CEECs) and on the following day (on gas markets and green power).

Patrick Rousseaux, representing the Directorate General for Energy and Transport (DG TREN) of the European Commission, presented an overview and a defence of the proposals as published in March 2001 to amend and supplement the Electricity and Gas Directives. The Commission's view is that these further measures are justified for three main reasons: (1) conditions are right for a further opening of the market, (2) most MS are opening further anyway, and (3) The European Heads of State and Government requested a further opening at their meeting in Lisbon on 23 and 24 March 2000. .

Mr. Rousseaux noted that a public hearing was held on 14 September 2000 in Brussels to assess the opinion of the stakeholders. For the electricity sector, he reported that there was general agreement at that time on the need for a strengthening of the requirements for unbundling. At present, there is often not "real unbundling" of the transmission system operator (TSO) in several Member States, meaning that the risk remains that the TSO can favour related generating companies in its despatching function. Regarding common rules on the duties and functions of regulators, he reported a general consensus in favour of new requirements, given that almost all Member States have established separate regulatory authorities. Only Austria and Germany were lacking an electricity regulator in September 2000, but Austria has subsequently established one as well. Regarding new provisions on public service obligations (PSOs), he noted that the Commission was seeking a requirement for "universal service" (an obligation to supply to all at reasonable prices) and better protection of customer rights (e.g. clear contractual terms, not just boilerplate protection for utilities).

As pointed out by the Commission in its communication of March 2001,[18] the proposal to amend the Electricity and Gas Directives can be divided into quantitative proposals and qualitative proposals. The ***quantitative proposals*** include a timetable for all electricity and natural gas customers, regardless of their size, to be able to choose their suppliers freely. In the electricity sector, all non-household customers would therefore be able to choose freely as of 1 January 2003, with full market opening two years later. In the natural gas sector, the proposed deadline for market opening for non-domestic users is one year later (1 January 2004), but all gas customers should be free by 1 January 2005 (convergent 100% opening of electricity and gas markets).[19] The ***qualitative proposals*** concern the minimum obligations regarding access to the network, consumer protection, regulation, security of supply, and the unbundling of the transmission and distribution function in integrated gas and electricity companies.

Regarding the proposed EU regulation on cross-border trade in electricity, Mr. Rousseaux observed that the Florence Forum has not been able to reach consensus on a cross-border tariff mechanism and that other elements are missing. The document drafted by the Commission proposes three different types of measures:

1) establishing compensation mechanisms for flows of electricity;
2) defining harmonised principles for cross-border transmission tariffs; and
3) allocating available interconnection capacity between national transmission networks.

Following Mr. Rousseaux's presentation, general concerns were expressed by certain participants over

[17] The Commission's proposals, first published in March 2001, consisted originally of two documents: (1) Proposal for a Directive of the European Parliament and the Council amending Directives 96/92/EC and 98/30/EC concerning common rules for the internal market in electricity and natural gas; and (2) Proposal for a Regulation of the European Parliament and of the Council on conditions for access to the network for cross-border exchanges in electricity. Several subsequent proposals to amend the Electricity Directive have been made available unofficially during 2001 and 2002.

[18] Communication from the Commission to the Council and the European Parliament – Completing the internal energy market, COM/2001/0125 final.

[19] This proposed time schedule for market opening was subsequently adjusted at the Barcelona Summit of the European Council, held on 15-16 March 2002, where the Council and the European Parliament were urged to adopt a proposal for the market opening of both electricity and gas, including freedom of choice of suppliers for all non-household consumers as of 2004.

the application of the proposed draft directive to the accession countries, and the related position of the Commission regarding transition periods (normally not allowed). In addition, Dominique Finon (IEPE, CNRS) raised the specific issue of the need to achieve some EU standardisation of power exchanges, given that there are significant problems with co-ordination of auctions at borders (e.g., to allow a French supplier to effectively bid into the Dutch market, while using the Belgian grid).

Inge Pierre, representing Eurelectric, reviewed the position of the European electricity sector. He noted the on-going and challenging work in defining proposed rules on CHP, including the effort to conduct a dialogue and reach consensus on criteria for determining "quality CHP". The European Commission has promised a directive on CHP, and it must take into account various national systems of promoting CHP (e.g. quota-based market mechanisms).

The critical and provocative review offered by Hans Auer, Richard Haas and Michael Stadler of the Vienna University of Technology on the status of competition in the European electricity sector provided the basis for a lively discussion. Rather than one market, there are at least five virtually separate electricity markets in greater Europe, and perhaps more (Auer). There are problems with insufficient unbundling, as well as various concerns with the structure and impact of transmission pricing (e.g. resulting in a decline in investments and of the quality of the transmission grid) (Auer). Concerns were also expressed about the merger and acquisition trends, i.e., that an EU electricity "cartel of 3 or 4 really dominant players" could develop and would have sufficient market power to manipulate prices (Auer). Hence, in five years, we may have solved problems with unbundling and market opening, only to find that we are left with a few strong players (Auer).

Regarding mergers, such concerns were acknowledged to be important, but such a pessimistic outlook is perhaps not necessary, given that new generation will come on-line from various sources (Rousseaux). Moreover, Nordpool demonstrates that even when there's a dominant position (of 50%) in Sweden, as soon as there is competition from other sources, Vattenfall cannot set the price (Finon). And competition and regulatory authorities are present and can maintain the 'game of competition' (Finon). The German situation, where there is no regulator and unclear rules, should be viewed as exceptional within the EU, and when corrected, the game of competition can work. (Finon). Notwithstanding this view, it is arguable that companies the size of EdF and EON cannot be forced to offer plant on the day-ahead market (Auer). We are close to a situation where large suppliers could manipulate the price, perhaps in a dry year (Auer).

The head of the Hungarian energy office, Mr. Kaderjak, responded on a positive note that no company at present could increase profits by curtailing sales. It is a possible future threat, but not yet the case. Competition is really likely in one or two years, he stated, and Austria, for example, must fear the onset of competition since they are closing borders.

On the issue of the application of reciprocity clauses to block imports, Mr. Auer stated that Austria was not a large player in this respect, and has excess capacity and significant hydropower, such that it was not an issue for most Austrian utilities. However, he noted concerns in Italy and Slovenia. Miha Tomsic (Slovenia) suggested that the impact of the convergence of market opening in gas and electricity was significant, noting that cross-border bottlenecks in electricity trade could perhaps be overcome through development of the gas transport network.

In a final presentation for the session, Mr. Cremer presented future patterns of electricity trade that could take place under several scenarios as modelled by their team. The question of the impact of wind power developments (P. Grohnheit from Riso National Laboratory), and of ecotax issues (Finon) on the reference case were raised and addressed.

Introducing competition in the Western European electricity market: A critical review

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Keywords. Liberalisation, Competition, ESI, Western Europe

Abstract. In Western Europe restructuring of the electricity supply industry (ESI) is (currently still) widely accepted and considered to be successful so far. Yet, the expectation of lasting cheap electricity is based on very simplified assumptions on the strategic behaviour of electricity generators and network operators. Straightforward, we are convinced that there are a lot of barriers for effective competition which will lead to highly volatile and rapidly increasing wholesale electricity prices. The major conclusion is that we are far away from a simple solution to achieve competition in a unique European electricity market. There are too many possible barriers in the whole supply chain which makes it unlikely that real competition in the European electricity market will ever take place!

Introduction

The directive of the European Commission on a common electricity market has triggered the liberalisation process in Western Europe. The three major items of this directive are:

- free choice of supplier for eligible customers and corresponding dates for eligibility (= schedule for minimal degree of market opening);
- unbundling of vertically integrated utilities into generation, transmission (TM) and supply;
- models for access to the grid

Yet the implementation of these features is described only very superficial. Especially, with respect to transboundary issues clear guidelines are missing. This led to the following major points of criticism:

- The guidelines for unbundling are to weak to ensure a separation of grid operation and generation sufficient to avoid market power over the grid;
- There are no basic principles and no clear regulatory requirements for TM pricing and access to the grid;
- No general rules for transboundary electricity exchange (if anything can be set by the EC only it is the condition for cross-border electricity trade)
- Customer discrimination: No deadline exists for 100% degree of market opening;

Anyway, competition in Western Europe has started and the restructuring of the ESI is (currently still) widely accepted and considered to be successful by and large. The major reason for this is that prices have dropped – at least for large industrial customers – and the expectation that enduring low prices will prevail over the next years.

Yet, surprisingly also in Europe up to now only few investigations exist on the conditions necessary for long-term competition in electricity markets. As has been argued by the authors already years ago – e.g. Haas et al (1997) and Haas/Auer (2001) – the expectation of lasting cheap electricity is based on very simplified assumptions on the strategic behaviour of electricity generators and network operators.

In this paper it is argued that many issues are currently neglected, which may lead to tremendous backlashes for competition in Western Europe. Straightforward, we are convinced that these backlashes will lead to highly volatile and rapidly increasing wholesale electricity prices.

The following barriers for effective competition are analysed in detail:

- How does geographically and timely different market opening affect competition?
- What are the problems and setbacks due to insufficient unbundling?
- How does an incorrect operation of and access to the grid affect competition?
- Which transboundary obstacles impact competition?
- Does the number of electricity generators develop in a favourable way for competition?
- What are the future perspectives for the ESI in Western Europe?

Requirements for effective competition

The European debate on restructuring of the ESI is sometimes confusing. The terms “deregulation”, “liberalisation” and “competition” are mixed up very often. Another major contradiction and misleading perception is that deregulation means “privatisation”.

In the following the most important basic principles for introducing competition are summarised. It is important to note that also the following order in which the different elements have to be introduced is important!

Conduct correct unbundling!

Competition requires the separation of parts of the ESI where competition is possible and parts where it is not, see Fig. 4. Currently, in generation and supply competition is pursued while the TM and distribution grids remain natural monopolies. The separation of electricity generators and the TM grid is important because of two reasons:

- to guarantee that potential new generators are not discriminated from access to the grid and
- to avoid cross-subsidization of generation by TM;
- to make correct pricing and access rules to the grid possible.

Introduce competition!

The basic principle of competition is that so many companies are competing that it is not possible for a single company to influence the market price and to exert market power. Hence, for real competition a large number of generators and suppliers is necessary to bring electricity prices down to marginal costs of generation. Moreover, excess capacities are required to make competition possible.

Yet, if utilities are mainly investor-owned (e.g. UK and U.S.), then, if something like liberalisation is under discussion they start to merge immediately and ultimately head towards virtual monopolies charging monopoly prices, see also Haas et al (2000) and Bunn (1998).

In this context mergers, acquisitions, and strategic alliances are important tools. What are the major reasons for this development? The basic principle is: First, private companies merge respectively buy shares from each other; second, competition decreases and, third, the prices rise, see Fig. 12.

In practice, e.g. only minimal shares of ownership held by otherwise competing utilities respectively joint-ventures can avoid competition.

Liberalise the market – No discrimination!

Liberalisation from the customers‘ point-of-view means that they may choose the supplier or the generator free. Of course, these choice must be possible for every customer! Otherwise, the group of customers which may choose the supplier free always has a strategic advantage and will benefit at the costs of the customers remaining captured.

Do not set up mandatory market structures!

In a functioning electricity market an equilibrium between different types of periodical markets exists – that is to say, between long-term contracts, short-term markets and balance markets. Of core relevance is that it is possible to sign long term contracts, e.g. bilateral or by futures. This possibility is a core difference between different liberalisation models. It did neither exist in the "old" English pool model nor in the Californian electricity market. Yet, it does exist in the very well functioning NordPool.

Deregulate!

The next important step in this process is to deregulate and re-regulate. A typical example of deregulation is to abandon the regulation of electricity prices and investment recovery. Of course, this step does only make sense if real competition is guaranteed. Otherwise price deregulation may lead to a skyrocketing of electricity prices!

Moreover, with respect to the transmission and the distribution grid it is necessary to re-regulate especially the prices and rights for access to the grid.

Internalise external costs!

It has to be ensured that all distortions that may occur between old and new capacities and between energy carriers with high externalities vs energy carriers with low externalities are abounded. Moreover, public acceptance of power stations and various fuel types has also to be taken into account. Hence, to ensure real competition in the long run externalities have to be included by proper taxes.

Privatise?

Eventually, the question remains whether privatisation contributes to more intensified competition. In our opinion privatisation does not mean "increase competition" but rather "strive for monopolies respectively oligopolies". Hence, full privatisation (100% private ownership) is not a condition for competition, which is proven impressingly by the Norwegian example.

Distortion of competition due to geographically and timely different market opening

The first major barrier for effective competition is the geographically and timely different opening of the market. It leads to customer discrimination and high transaction costs for transboundary electricity trade due to reciprocity.

Customer discrimination is caused by the EU directive which prefers liberalisation for large customers and discriminates households. Due to the EU directive the liberalisation targets are:

19 February 1999:	Users taking >40 GWh/yr, or 25% of national market
19 February 2001:	Users taking >20 GWh/yr, or 28% of national market
19 February 2003:	Users taking >9 GWh/yr, or 33% of national market
2007:	Review of liberalisation process

Moreover, the EC announced recently that it intends to fully open the electricity market. Yet, this is still subject to approval by the member country governments and it is not clear when it will happen.

This discrimination leads to a distortion of competition in that way that large customers get by far lower energy prices than private households.

Table 1 and Fig. 1 depict the opening of the market in different EU member countries in 2002. Some countries like UK, Sweden, Germany, Finland, Norway and Austria have fully opened their market (=100 %). Others like France, Greece, Ireland have opened only the minimum.

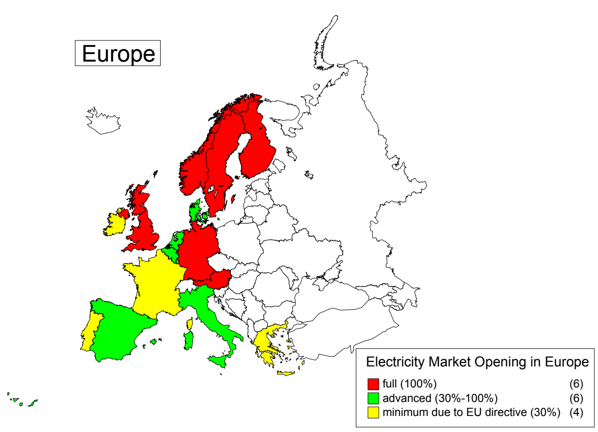

Fig. 1. Market opening in EU countries, Norway and Switzerland as of 1 January 2002. (See close-up on page 9).

Table 1. Electricity directive implementation (1 January 2002) in EU countries Norway and Switzerland

Country	Eligible customers	Market opening
Austria	all	100%
Belgium	>100 GWh	35% (100% in 2010)
Denmark	>10 GWh + distributors	90% (100% in 2002)
Finland	all	100%
France	>20 GWh (16 GWh)	30% (34% in 2003)
Germany	all+distributors ?	100%
Greece	>100 GWh + others TBA	>26%
Ireland	> 4 GWh	28% (32% in 2003)
Italy	>9 GWh	40%
Luxembourg	>100 GWh	45%
Netherlands	2 MW/20 GWh + distrib. for elig. cust.	33% (100% in 2007)
Norway	all	100%
Portugal	>9 GWh + distrib. for 8% of volume	34%
Spain	> 1GWh	42% (100% in 2007)
Sweden	all	100%
Switzerland	No final customers	0 %
UK	all	100%

Norway (not in the EU) has already fully opened its market whereas in Switzerland (not in the EU) the market opening is 0%.

This leads to the fact that, currently, Western Europe (15 EU member countries plus Norway and Switzerland) is still far away from a joint harmonised electricity market. It consists of at least five separated markets, see Fig. 2. These are:

1) UK and Ireland, 2) The Nordic countries, 3) Spain and Portugal, 4) Italy, and 5) Central Europe (France, Germany ...).

It should be noted that, of course, these markets are to some extent also separated by geographical transmission capacity constraints and legal issues, mainly limited access to the grid (especially in France and Germany). With respect to Italy it has to be stated that the connection to other countries (mainly France and Switzerland) is mainly due to long-term contracts.

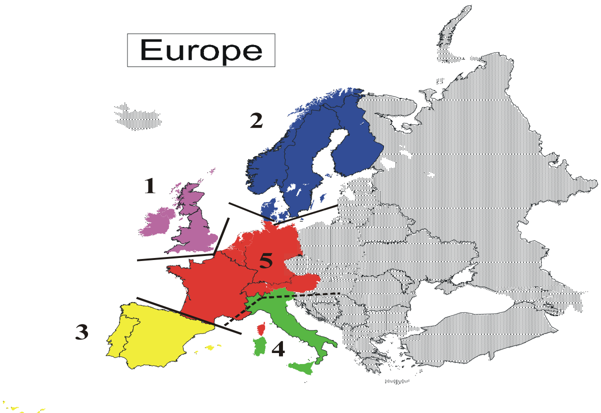

Fig. 2. The different separated electricity markets in Western Europe

Evidence for the existence of these separated markets is given by the different wholesale electricity market price levels, which are depicted in Fig. 3. Prices over the last years have been lowest in the Nordpool and highest in the English pool.

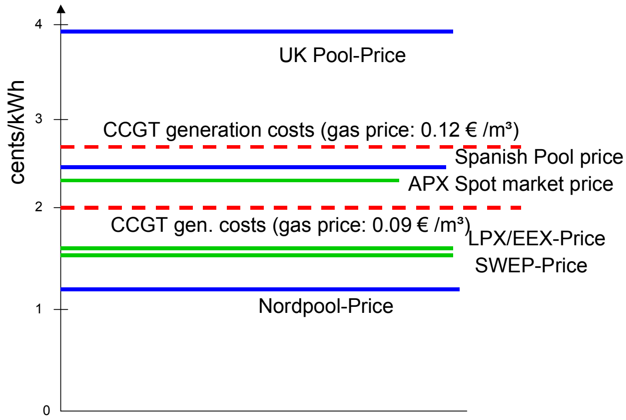

Fig. 3. Range of current wholesale electricity prices and generation costs in different Western European markets

The problem of insufficient unbundling

The next question is: What is the state-of-the-art with respect to Unbundling of the Western Europe ESI?

Correct unbundling is based on the idea that competition requires the separation of parts of the ESI where competition is possible and parts where it is not, see Fig. 4. Currently, in generation and supply competition is pursued while the transmission and distribution grids remain natural monopolies. The separation of electricity generators and the transmission grid is important because of the following reasons:

- to ensure that potential new generators are not discriminated from access to the TM grid and
- to avoid cross-subsidization of generation by transmission.

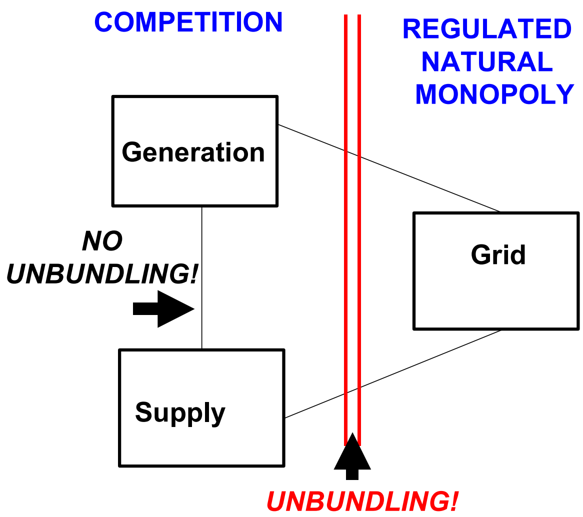

Fig. 4. Correct Unbundling of the ESI!

Currently due to a lack of rigorous unbundling market power of generators over the grid is a major obstacle for a real competitive electricity market. Especially in Germany and France it is likely that incumbent generators will retain market power over the transmission grid over the next years. Currently the large vertically integrated German utilities make high profits with the grid and no profits or even losses in generation. The major problem in Germany is that due to private ownership of the large vertically (generation + transmission) integrated utilities it is virtually impossible to achieve a rigorous unbundling. In general, the majority of EU countries has implemented at least legal unbundling. In Scandinavia, UK and Spain separate grid companies exist, see Table 2 and Fig. 14. With respect to access to the grid only Germany has chosen negotiated third party access (nTPA). Remaining EU member countries (incl. Norway) have implemented regulated third party access (rTPA), see Table 2.

Table 2. Type of unbundling and ownership of the TM grid in EU member countries and Norway in 2002

Country	Unbundling 2002	Ownership 2002
Austria	Legal (APG); Management (TIWAG, VKW)	3 Owners / 3 Operators (APG, Tiwag, VKW)
Belgium	Legal [1]	1 Owner / 1 Operator (Electrabel)
Denmark	Legal	1 Owner / 1 Operator per Island (Eltra, Elsam)
Finland	Ownership	1 Owner / 1 Operator (Fingrid)
France	Management	1 Owner / 1 Operator (RTE)
Germany	Management	Many Owners / Many Operators
Greece	n.a.	1 Owner / 1 Operator
Ireland	Legal	1 Owner / 1 Operator
Italy	Legal	Many Owners / 1 Operator
Luxem-b.	Management	
Netherlands	Legal [2]	Many Owners / 1 Operator (TenneT)
Norway	Ownership	Many Owners / 1 Operator (Statnett)
Portugal	Legal	Many Owners / 1 Operator
Spain	Ownership	1 Owner / 1 Operator (REE)
Sweden	Ownership	1 Owner / 1 Operator (Svenska Kraftnät)
UK	Ownership (E&W); Management (Scotland, N. Ireland)	1 Owner / 1 Operator (NGC)

Legend: [1]Belgium: although the TSO has not been nominated yet
[2]The Dutch government intends to buy the majority share in the Dutch TSO

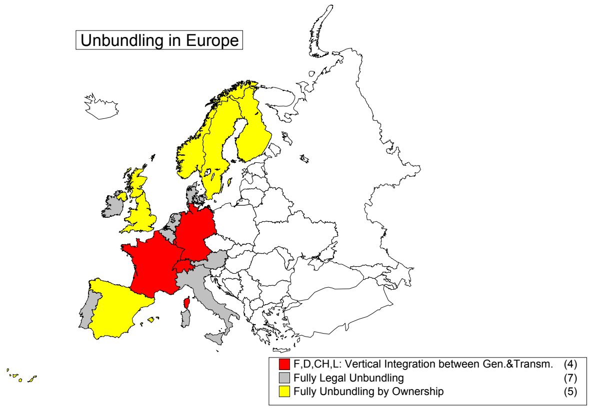

Fig. 5. Degree of unbundling of the TM grid in Western Europe 2002

Of further relevance is the principle, that suppliers can choose their generator free. This leads to the perception that suppliers must also be able to generate their electricity themselves! Hence, an unbundling of generators and suppliers is <u>not</u> necessary! On contrary this type of unbundling is counterproductive as the recent developments in California prove!

Table 3. Access to TM grid and type of TM price regulation in EU member countries and Norway in 2001

EU Country	Access to the grid 2002	Type of TM price regulation 2002
Austria	rTPA	cost based
Belgium	rTPA	cost based
Denmark	rTPA	cost based
Finland	rTPA	no direct regulation
France	rTPA	cost based
Germany	nTPA	Cost based
Greece	rTPA	cost based
Ireland	rTPA	cost based
Italy	rTPA .. eligible customers SB(rTPA)..captive customers	price cap
Luxembourg	rTPA	cost based
Netherlands	rTPA	cost based / maximum tariff
Norway	rTPA	government bond rate plus 1%
Portugal	rTPA .. eligible customers SB(rTPA)...captive customers	cost based
Spain	rTPA	standard costs
Sweden	rTPA	no direct regulation
UK	rTPA	price cap

Note: rTPA...regulated third party access, nTPA...negotiated third party access, SB...Single Buyer model.

Correct operation and access to the grid

With respect to the operation of and access to the grid the principal requirements are:

- to ensure that the existing grid is used and upgraded/extended with maximum benefit for society,
- to assure that those who have the highest Willingness-to-pay for the use of the grid get the right to use it;

Of course, these issues are very closely linked to a correct unbundling.

Derived from these basic objectives the most important questions with respect to access to the grid and the magnitude of prices in various countries are:

1) Who has the right to use a TM line? When? Over which period of time?
2) What is the correct magnitude of the price? How to price bottleneck capacity?
3) How is the structure of pricing? (Fixed fee, fee per kW or per kWh)
4) Is there a fee for changing the supplier?
5) Who pays for an extension of the grid if a new generator wants to feed in at a point where no sufficient grid exists?

To answer these questions we first have to identify the basic principles for TM pricing. These are:

- The prices should reflect the marginal costs of the use of the grid
- The pricing system should be simple and transparent
- Incentives to strike a balance between supply and demand should be provided
- The pricing system should guarantee the recovery of the operation costs
- But: What about revenues from auctions if we do not want that the grid operator makes excessive profits?

Introduction of auction based systems of transmission rights

A major problem is that the right of access to the grid is often not driven by economic incentives. To find an optimal solution we analyse now how an optimal TM pricing system looks like. We have to take into account different possible demand cases:

1) If excess capacity is available it is sufficient to recover the costs by charging a price equal to the average costs.
2) Yet if demand is close to capacity available the WTP of the different customers has to be taken into account e.g. by means of an auction-based price-setting procedure. This ensures that capacity is used in the economically most efficient way.

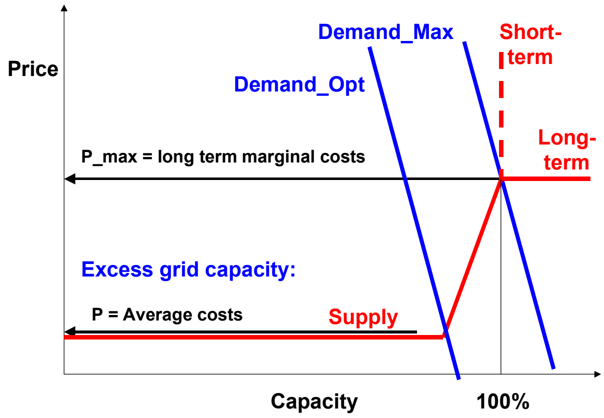

Fig. 6. TM prices under perfect vs imperfect access to the grid

A solution could be auction-based TM rights. An example:

TenneT, the Duch transmission system operator, is preparing a plan together with the German and Belgian TSOs for the auction of cross-border capacity. Under the scheme specific percentages of total interconnection capacity are allocated for annual, monthly and daily contracts, and auction these off to the highest bidder. Safeguards have to be built into the system to avoid gaming and limit large traders from buying all available capacity. The scheme is being studied by TSOs in other European countries facing cross-border capacity problems (e.g. Spain). A similar auction system between E-ON-Grid in Germany and Eltra in Denmark was launched in 2001 and, after some difficulties, is now working well.

Market participants evaluate an auction-based system fairer to all traders in the market – avoiding potentially discriminatory processes like „first-come, first-serve“, proportional or merit-order allocation.

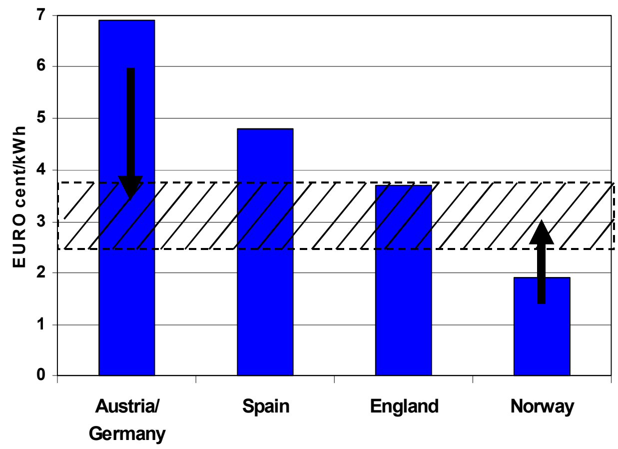

Fig. 7. Share of transmission and distribution costs in selected Western European countries 2001

Differences in national TM fees

Competition in various EU member countries is further curtailed by high transmission fees and differences in transmission pricing models. Fig. 8 compares the share of transmission and distribution costs for residential customers in selected Western European countries in

2000. As can be seen they vary tremendously. On the one hand, they are still high in recently liberalised markets like Austria and Germany.

According to the announcements of the regulatory bodies in these countries they are expected to decrease in the future. On the other hand, in Norway the transmission and distribution charges are extremely low. As a consequence, currently less investments to maintain the grid take place. In order to change this situation it is likely that in the future in Norway charges for transmission and distribution have to increase.

An example for large differences in grid access prices within a single country is Germany. In 2001 the prices varied between 3,13 pf/kWh (1,55 cents/kWh) and 7,10 pf/kWh (3,5 cents/kWh).

Will the incumbents retain market power?

Finally, the major crucial issue in the discussion of competition with respect to TM and access to the grid is whether incumbent utilities will manage to retain discrete market power over (part of) the high-voltage grid or whether in a serious unbundling the TSO will become independent. Some examples which depict this problem are:

The Berlin utility BEWAG has very small TM capacities. Hence, it rejected to transmit electricity from other utilities to customers in Berlin. Yet, the FCO (Federal Cartel Office) ruled that due to the "law" of unbundling BEWAG cannot reserve 100% of its TM capacity for own generation. BEWAG has been forced by the watchdog to open 20% of its TM capacity for other utilities.

In The Netherlands the Dutch network operator has been fined the anti-cartel authority NMa relating to a complaint by the Norwegian company Norsk Hydro. The NMa ruled that SEP has abused its dominant market position by unfairly blocking grid access to Norsk Hydro.

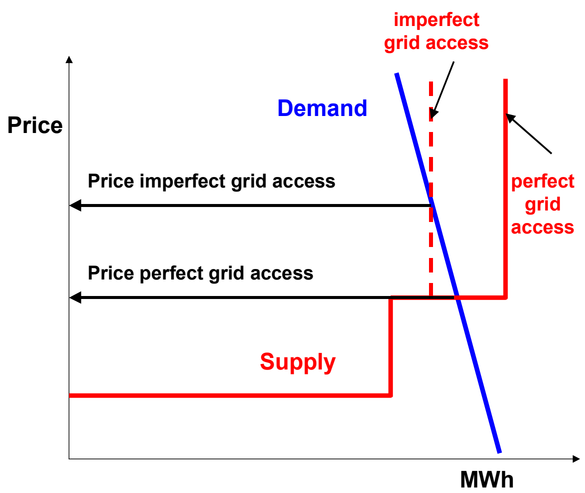

Fig. 8. TM prices under perfect vs imperfect acecss to the grid

How does imperfect access to the grid influence competition?

What if no correct unbundling is conducted and network operator exerts market power? How does imperfect grid access influence electricity trading? It leads to the situation depicted in principle in Fig. 8. Not all capacity available shows up in the supply curve and hence demand intersects with the supply curve (broken line) curtailed by imperfect access to the grid. Straightforward, this leads to a higher market price for electricity than under perfect access to the grid.

Transboundary restrictions

In addition to national problems The most important constraints limiting transboundary electricity trade are:

- Reciprocity in transboundary trade;
- Bilateral differences in the magnitude of prices;
- (In-) Compatibility of transboundary rules (eg reciprocity due to different eligibility of customers)
- (In-) Compatibility of TM tariff schemes in different countries
- Limited capacities: At some nods of the grid the capacities available to transmit electricity are smaller than the capacities demanded by the market. This leads to the problem of congestion;
- Non-Transparency in tariff structures, access rights, magnitude of access fees

Bilateral differences in transmission tariffs

In Fig. 9 the differences in transmission tariffs for selling electricity from Germany to Austria and vice versa are depicted. All numbers in these figures are in €/kWh.

According to these bilateral differences it is e.g. for a customer in Bavaria more attractive to buy electricity in Austria than vice versa (if the price for electricity generation is the same).

Political reasons

Since France was not able to meet deadline of minimal market liberalisation in 1999 the anger of neighbouring countries over France's foot dragging has turned into a big problem. The Netherlands, UK, Germany and Spain, having already liberalised, found themselves unable to access the French market, while the reserve was not the case. Spain has threatened to remove EdF's supply license. Moreover, Belgium, the Netherlands, and Spain have suggested that French imports of electricity will be limited unless France liberalises further.

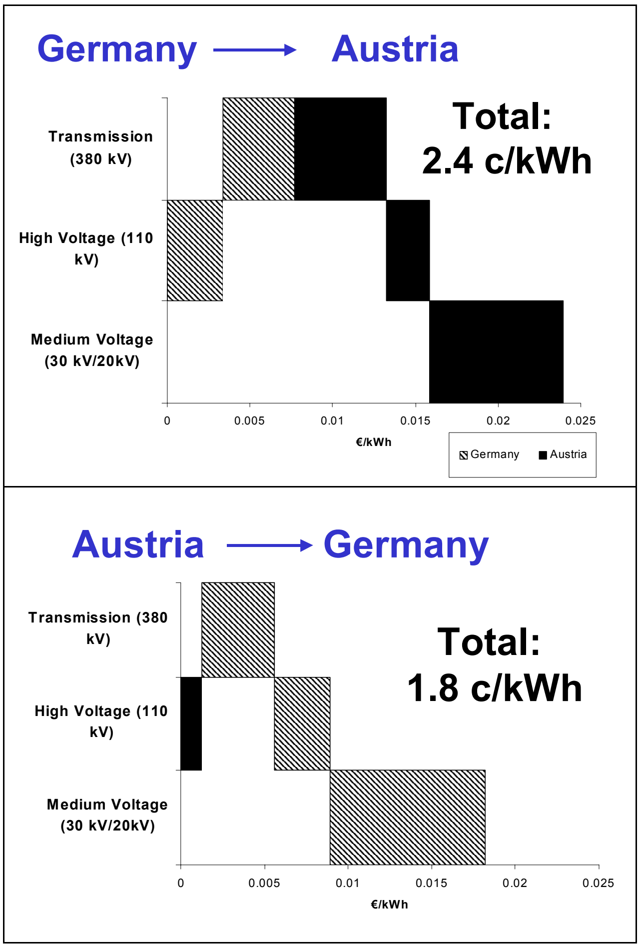

Fig. 9. Bilateral differences in the transmission tariffs between Austria and Germany (feed-in level 110 kV, demand level: 20 respectively 30 kV). Source: Haas et al (2000).

Old long-term contracts

Spain's national grid company Red Electrica (REE) expects to make 80% of the cross-border capacity of 1,100 MW with France available to competition when it started auctions in 2001. But this measure mainly depend on the results of renegotiation and perhaps early cancellation of its low-price, long-term electricity import contract with Electricité de France (EdF). That long-term contract currently occupies 500 MW of import capacity, with much of the rest also currently tied up in contracts with EdF and Electrabel (Belgium). REE will keep 20% of capacity back to cover balancing needs. REE is expected to make about 30% of import capacity available in annual auctions, and allow resale of import capacity in monthly auctions. The bulk of capacity, around 50%, should be up for grabs in weekly auctions. Anyway, the recent crisis in California has to some extent mitigated this problems.

Generators: Heading for strategic prices

Another tremendous barrier for effective competition, which increases continuously, is the decreasing number of generators. Remember that the fundamental principle of competition is that there is a large number of companies who do compete!

Yet, this does not fit with the objectives of private companies. These are:

- Satisfy shareholders
- Prices and profits as high as possible
- Avoid competition!

Table 4. Major mergers, acquisitions and share purchases in Europe 1995- 2001

Acquiring Company	Acquired Company	share
EdF	London Electricity (UK)	100%
EdF	SWEB generation, supply (via London Electricity)	100%
EdF	ESTAG (A)	25%+1vote
EdF	EnBW (D)	25%+1vote
Vattenfall (S) (via Vasa Energy)	Stadtwerke Rostock (D)	12,55%
Vattenfall (S)	HEW (D)	25%
Texas Utilities (US)	Eastern (UK)	100%
ScottishPower (UK)	Manweb (UK)	100%
National Power (UK)	Midlands Electricity (UK)	100%
PowerGen (UK)	East Midlands Electricity	100%
Preussen Elektra (DE)	EZH (NL)	25%
Scottish Hydro Electric	Southern Electric	100%
PNEM-MEGA	PNEM/MEGA Limburg	merger
EnBW (D)	EVS/Badenwerk	merger
BirkaEnergi (SE)	Stockholm Energi/Gullspang	merger
Electrabel (BE)	EPON (NL)	40%
E-ON (D)	Preussen Elektra/Bayernwerk (D)	merger
RWE (D)	VEW (D)	100%
Vattenfall(S) /HEW(D)	VEAG (D)	51%
E-ON (D)	PowerGen (UK)	100 %
E-ON (D)	Sydkraft (S)	51 %
RWE (D)	KELAG (A)	22 %
E-ON-Hydro (D)	VERBUND/Austrian Hydro Power (A)	merger (pending)

The "merger-mania" in the last years in Western Europe – see Table 4 – proves that the major strategy of investor-owned electricity generators is not to compete but rather to merge or to purchase shares. The mergers pursue two major objectives:

1) An official one: to achieve a potential for savings due to synergies;
2) An unofficial one: to become able to set prices as high as possible. In practice minimal shares owned by otherwise competing utilities or joint-ventures can avoid competition and allow to set strategic prices;

Fig. 11 clearly shows that the major current goal of large European utilities is getting larger and heading towards oligopolies. From the 17 largest generators which existed in 1999 today only 11 exist. Of particular concern with respect to competition is the situation in Central Europe (France, Germany, BeNeLux, Austria) where only 5 large blocks dominate the market: EdF/EnBW, RWE, E.ON/Sydkraft/VERBUND, HEW/Vattenfall/ VEAG, and Electrabel. It is hard to believe that this structure ensures effective competition even in the short-term. It is much more likely that the major objective is to set strategic prices. Indeed, as Fig. 19 shows electricity prices in Central Europe have been increasing steadily since 1999.

This leads to the following pattern which can be observed in most countries where liberalisation takes place: First, prices decrease due to efficiency gains but after a short period of time they start to increase considerably, mainly due to the exertion of market power and a lack of excess capacities, see Fig. 10.

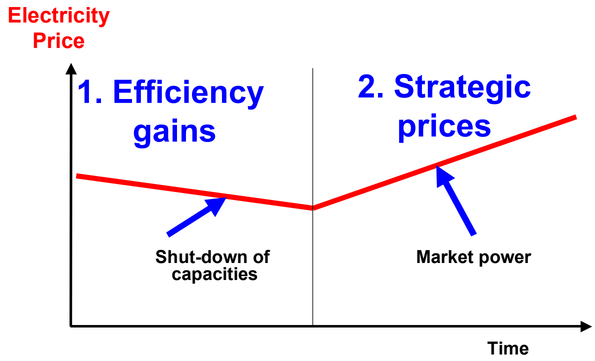

Fig. 10. The ambigous role of shut-down of excess capacities

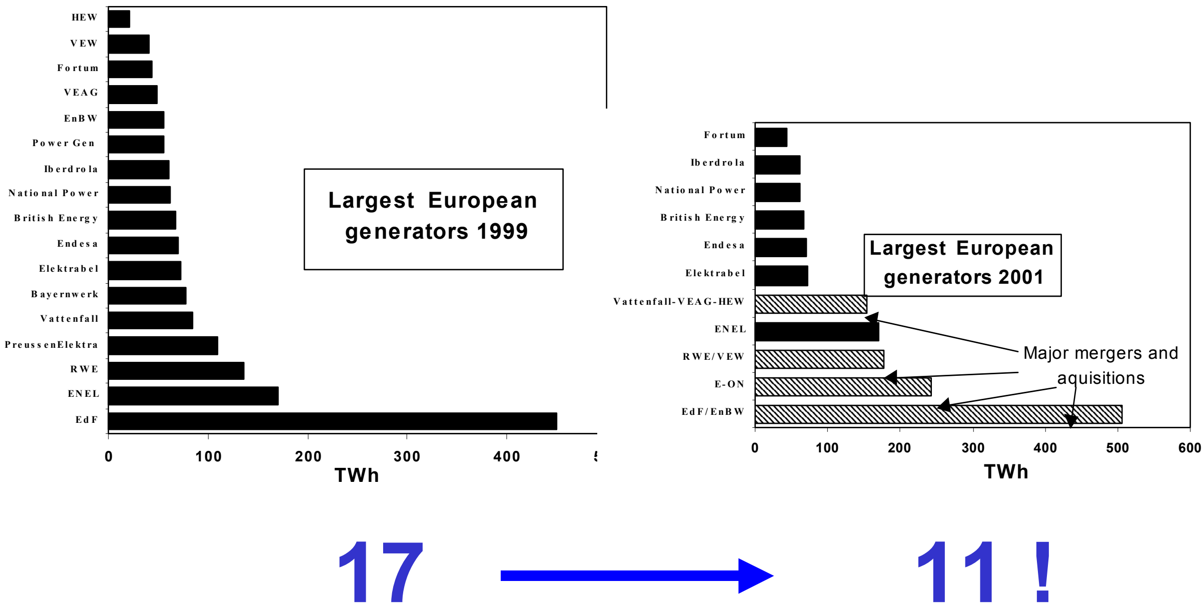

Fig. 11. Ranking of the largest European electricity generators in 1999 and 2002. Source: annual reports.

An important issue in this context is the resulting shut-down process of excess capacities. If excess capacity exist and and utilities compete at least to some extent the price they receive for electricity will only be equal to the short-run marginal costs, see Fig. 13. Under perfect competition without remarkable excess capacities the price will be equal to the long-run marginal costs (LRMC). But if there is no competition the price will be set strategically and might be substantially higher than under competition especially if demand is very inelastic, see Fig. 14. And e.g. the large German utilities E.ON and RWE have already announced that they intend to close substantial capacities.

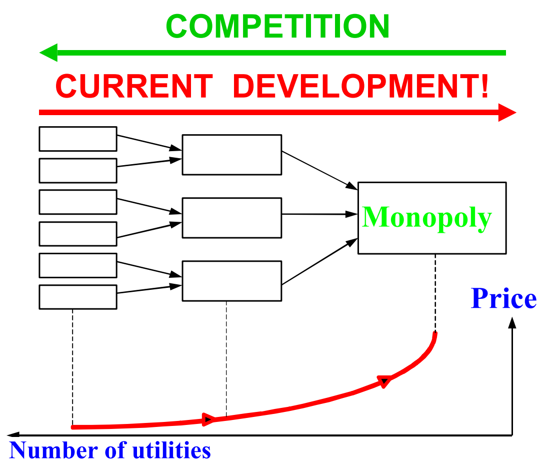

Fig. 12. Current vs. ideal development of the number of generators

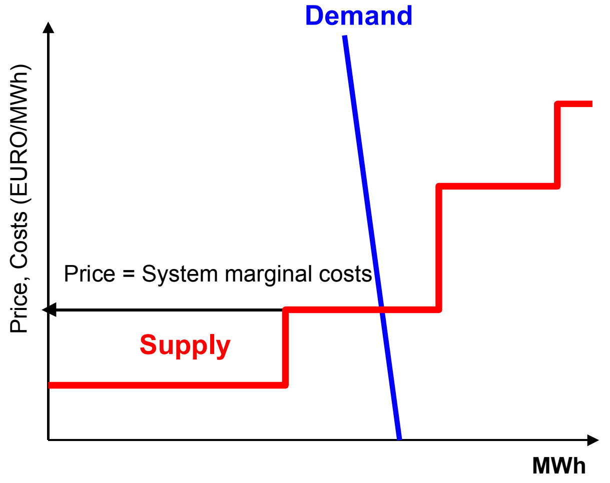

Fig. 13. Competitive prices with existing excess capacities

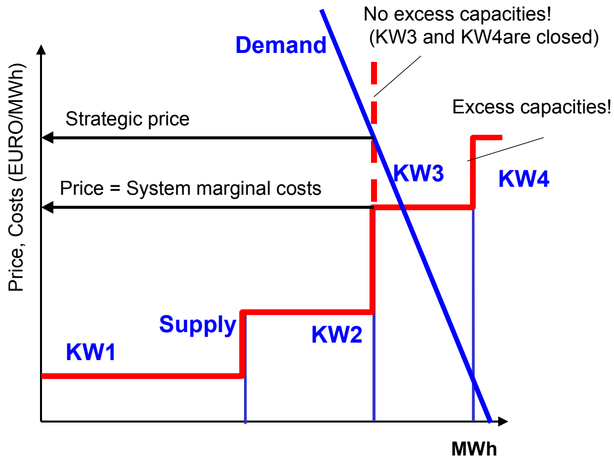

Fig. 14. Strategic prices given a lack of excess capacities

Future perspectives

Finally, the crucial question is: What does the future hold for liberalised electricity markets in Western Europe?

Most important in this context is the question how prices will develop. First it is of interest how wholesale electricity prices have developed in recent years in major European markets. Fig. 15 depicts that there are considerable differences between different markets. The UK pool price was about three times higher that the cheapest market, the NordPool. Yet, in 2001 the prices in the NordPool has caught up, mainly due to looming capacity shortages. Also the Spanish pool price is higher than the average. In Spain also capacity shortages are looming. The electricity price at the German bourses EEX (Frankfurt) and LPX (Leipzig) in 1999 and 2000 was lower than the Spanish and English pool price. But it has caught up considerably at the end of 2001.

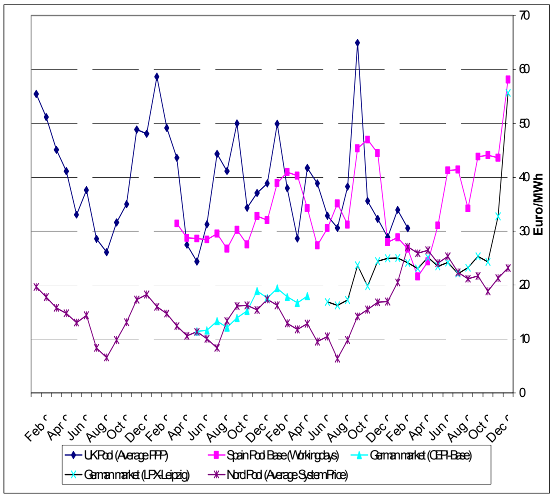

Fig. 15. Development of electricity generation prices in major European markets

Regarding the future development of electricity prices an important issue is the volatility of hydro power. As Fig. 16 shows for Austria hydro power availability varies tremendously over time. With an average of 1 the maximum over a year is about 1.2 while the minimum is 0.8. Hence, the minimum is only 2/3 of the maximum! This relationship is even more dramatic if we look at it on a monthly base.

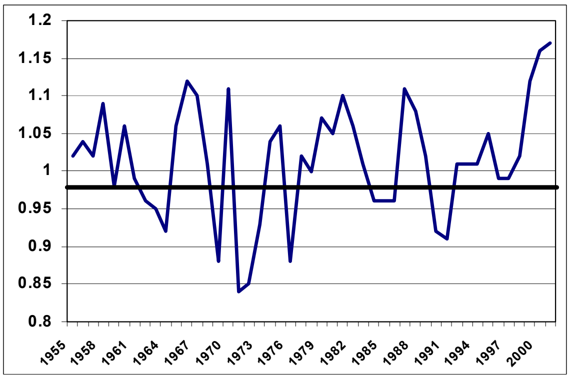

Fig. 16. Annual variation of hydropower availability in Austria

As can be seen from Fig. 17 for Austria (and the conditions in other Central European countries with large hydro power shares like Switzerland and France are very similar) in winter months the minimum production in the long run is only half of the maximum! Moreover, in many countries there is a feedback of available hydropower on the availability of nuclear power plants due to cooling capacity. Hence, to some extent the reduction in electricity generation due to less hydro availability will be intensified by a decrease in nuclear generation!

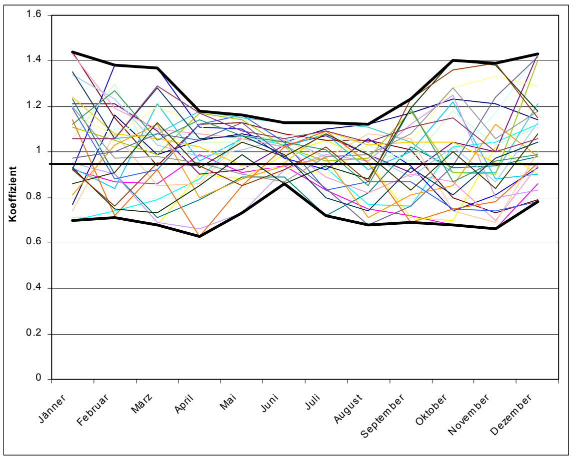

Fig. 17. Monthly range of Hydro Power availability in Austria

Summing up, most of the arguments raised above indicate that electricity prices in Europe will start to increase soon. There are some further aspects not discussed comprehensively in this paper which support this argument:

- Increasing dependence from natural gas and increasing natural gas prices;
- Increasing horizontal integration, especially of gas and electricity;
- Increasing reliance on imports in most countries leaving open the question: Which country will export electricity in the long run?
- no incentives for building new capacities, neither in generation nor in TM;

Hence, it is likely that the development of electricity prices over time in liberalised markets follows in principle the pattern shown in Fig. 18.

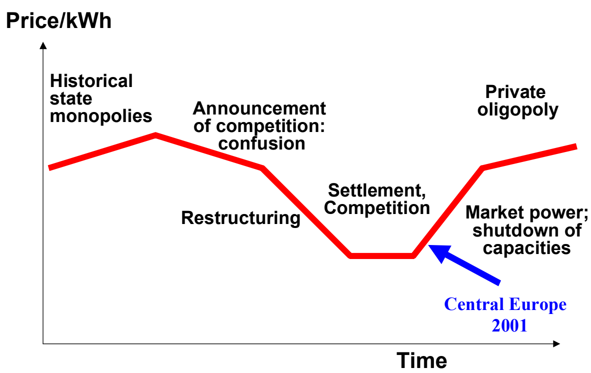

Fig. 18. Development of electricity prices over time (in principle) in liberalised electricity markets.

Fig. 19 depicts the recent developments on the wholesale level in Germany from 1999 - 2001. It can be seen that since 1999 the wholesale prices have been increasing almost continuously.

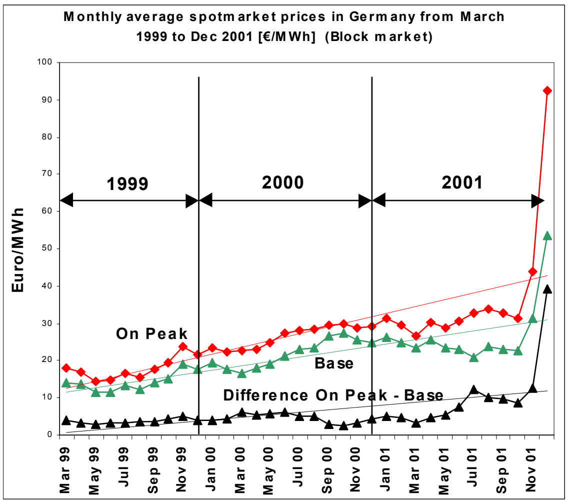

Fig. 19 Recent development of wholesale electricity prices in Germany 1999-2001

Another interesting case in point is the dynamics of various developments. Above the fundamental conditions for effective competition in electricity markets have been summarised. With respect to these different conditions currently the basic strategy of incumbent utilities in Western Europe appears to be as follows: There are two phases:

- In Phase 1 competition would be possible because of excess capacities and a sufficient number of generators exists. But it is curtailed by barriers for access to the grid, for changing the supplier and limited market opening in some countries. That is to say, barriers are maintained to postpone real competition until there is no more a relevant number of competing generators. Moreover, competition is distorted in Phase 1 by to cheap generation prices and to high prices for access to the grid;
- In Phase 2 when finally the most pressing problems regarding access to the grid and customer switchover are settled (e.g. due to the so-called „Florence-Process") competition will be no more possible because of a lack of competing generators and a lack of excess capacities.

TWO PHASES OF MARKET LIBERALISATION:

	Today	2005
Unbundling	NO	YES
Fully open market	NO	YES
Comp. in generation	YES	NO
Comp. in supply	YES	NO

Fig. 20. Two phases of market liberalisation

Conclusions

Policy makers and the public in Western Europe are currently still blinded by the recent drops in electricity prices. Yet, the future looks less bright. The major conclusions of this analysis are:

- We are far away from a simple solution to achieve competition in a unique European electricity market. There are too many possible barriers in the whole supply chain which makes it unlikely that real competition in the European electricity market will ever take place!
- Competition requires a rigorous separation of market elements where competition is possible (generation & supply) and parts which remain natural monopolies (transmission grid). Unbundling of generation and transmission by means of separate accounting as currently practiced in various countries is not sufficient for real European-wide competition!
- A major condition for competition is many generators. Yet, in Western Europe currently the number of generators decreases dramatically mainly because of strategic alliances and mergers. Unless the European Commission takes regulatory steps to ensure that there is a sufficient number of competing generators in Western Europe it is unlikely that effective competition will ever take place!
- Cheap electricity prices can be sustained only if excess capacities are available. We predict that after the dust of merging, acquisitioning and share purchasing has settled capacities will very soon become scarce in Western Europe and the volatility and the absolute level of wholesale electricity prices will increase substantially;
- An important issue in this context is the temporarily decrease in hydro power we have to expect in the near future after years of hydro production far over the average;
- Yet, the development described above also provides new opportunities, especially for more efficient use of electricity and decentralised generators. The gap between decreasing large "old" capacities and increasing demand for energy services has to be met by increases in energy efficiency and new decentralised generation facilities. These will be based most favourable on renewable energy sources. High electricity prices will of course support these developments.

Finally, we state that liberalisation is not the target but a means. More precisely, it is one small piece in a large puzzle of competition requirements. Or as John Chesshire (1999) puts it "liberalisation is a means, not an end!"

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Impacts of market liberalisation on the electricity supply sector: a comparison of lessons learned in Germany and Austria[20]

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Abstract. The specific impacts of market liberalisation on the electricity supply sector depend on many different factors and boundary conditions. A comparison of these impacts in Germany and Austria, two countries which both participate in the European internal market and have a central geographical location in Western Europe, and which both have borders and important trade relationships with Central European countries, provides some important insights. Furthermore, the paper also covers the expected influence of the increase in the electricity trade volumes in the two countries, also with their Central European neighbours, and the concerns that this may lead to conflicts in the achievement of targets in energy, environmental, and climate change policies aimed for both at the national and at the European level.

Introduction

The liberalisation of the electricity sector, like in other network-based industries, induces substantial structural change, and the consequences for a particular country are often hard to predict, as experience has shown, e.g., in the UK and Norway. This change causes an urgent need to often rapidly adjust to a new market environment – by adapting the prices and quantities offered, the marketing strategy, and the portfolio of products and services purchased and sold. However, the strategic and operational adjustments required may be quite different, depending on the particular boundary conditions for the electricity supply industry in question (e.g., in terms of domestic energy resource base, CO_2 reduction obligations, etc.) and the *actual* impact of market liberalisation on the electricity supply sector.

In the course of the European electricity market liberalisation, as stipulated in the EU Directive 96/92/EC, the German federal legislation decided for an instant full liberalisation by April 1998 (EnWG 1998), while the Austrian parliament (at first) opted for a stepwise market opening in line with the minimum limits given in the EU Directive 96/92/EC, starting in February 1999. Following the rapid restructuring of the power supply industry in Europe, however, and in the light of

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the uneven exposure of Austrian utilities to competitive pressures, it was decided in 2000 to completely open the Austrian power market by 1 October 2001 as well, way ahead of many other EU member states.

Given the different market opening schedules and other differences, such as in market size and in the pre-opening organisational and ownership structure of the utilities, it seems to be worthwhile to compare the impacts of liberalisation in the two countries – with an annual per capita electricity consumption of beyond 6,500 kWh, comparatively high environmental standards, and traditionally strong electricity trade relationships with Central European countries. Besides, factual competition in the power sector in both countries has developed at an impressive pace. The findings may also provide some useful hints for utilities and public administration in countries that are planning to open their electricity markets within the next couple of years, too, such as Croatia, Slovenia, and Switzerland.

Primary energy supply mix for power generation – the starting point

The primary energy basis for electricity generation in the two countries is significantly different, and can be expected to have some specific implications on the behaviour of the participants in the electricity markets in the two countries. Whereas electricity generation of the German power sector has been traditionally heavily dependent on coal (hard coal: ca. 25%; lignite: ca. 26%) and nuclear energy (ca. 36%), with almost negligible shares of hydro (1.5%) and wind power (0.4%), respectively. In contrast, the Austrian power sector has its foundation in hydro power (ca. 44%), fossil-fuel based thermal power generation (oil: ca. 9%; gas: ca. 30%: coal: ca. 12%; mostly in co-generation plants), and – as a result of the 1978 people's referendum on the Zwentendorf plant – no nuclear generation (ARGE Energiebilanzen 2001; Statistics Austria/E.V.A. 2001; own estimates).[23]

In Germany the current market share of natural gas of about 10% is expected to rise considerably in the future, mainly because of the anticipated continued boom of combined-cycle power plants due to their lower capital cost (and thus lower financial risk), relatively low CO_2 emissions per kWh of output – and, most recently, also the planned phasing out of nuclear power within the next two decades, as agreed upon between the German government and power industry. Altogether, the fossil-fuel share of electricity generation is expected to rise, as it is unlikely that the phase-out of nuclear capacity can actually be compensated immediately by increases in energy efficiency and/or the use of renewables alone. Restrictions imposed by the German Kyoto obligation can be expected to lead to increasing net electricity imports from neighbouring countries with a lower carbon fuel mix.

In Austria the situation is markedly different, at least in the short to medium term. Given the high dependency of Austria on (clean, domestic, and currently competitive) hydro power, fossil-fuel plants are merely used as back-up systems in times of high power demand and low river flows/pump storage levels. This dispatch priority, however, leads to a considerable amount of under-utilized (and hence quite expensive) reserve capacity, which at the same time is rather difficult to reduce, depending on the market situation in terms of demand growth, fuel prices, electricity import options and transmission capacity constraints, and the required local physical reserve capacity – especially in times of low precipitation levels (cf. Schröfelbauer 2001, esp. Fig. 8). In its current restructuring activities, which were started as early as 1994, the largest Austrian power producer, Verbund, is concentrating its power plants into two distinct and essentially centrally managed blocks for hydro and thermal power plants, enabling to exploit important synergy potentials in plant operation, maintenance, and administration.

Market opening – the window of opportunities

Despite some political will to liberalise, exemplified recently by the full opening of the Austrian power market by 1 October 2001, the electricity markets both in Germany and Austria are still characterised by important market barriers and impediments to competition. In particular, two issues need to be sorted out urgently: (i) the transmission tariffs and capacities available and (ii) the accepted impacts of liberalisation on national integrity.

The EU Directive 96/92/EC allows for different speeds of market opening, but demands a minimum speed for all member countries, measured in terms of an annual electricity consumption threshold above which electricity consumers are free to choose their supplier (19 Feb 1999: 40 GW equiv. to 26.5%; 19 Feb 2000: 20 GW equiv. to 30%; 19 Feb 2003: 9 GW equiv. to 35%; percentages approx.).[24] The German government and parliament decided to open the electricity market completely in a single step by 24 April 1998, which included:

- immediate free choice of electricity supply for all consumer categories;
- financial unbundling of vertically integrated utilities (minimum requirement);
- negotiated third-party access (nTPA) to the grid;
- allowance of power traders.

An immediate full opening of the market was chosen with the argument that smaller electricity consumers would either demand the distributors, generators or traders to offer similar conditions to those offered to the larger consumers (threat of changing the supplier), or they would merge their small electricity demand to

[23] Note that here thermal-based input fuels appear much more important than hydro power in terms of primary energy contributions for a given electrical output, because thermal conversion losses are also counted as contributing to primary energy production.

[24] Percentages are approximate, calculated as the total electricity share consumed by final consumers with an annual consumption level exceeding 40 GWh, 20 GWh, and 9 GWh (according to the three liberalisation steps scheduled in the EU Directive 96/92/EC).

larger quantities (e.g. by establishing joint purchase syndicates) in order to receive more favourable prices from the (now) competing electricity companies.

Table 1. Individual electricity transmission and distribution rates, Germany (as of April 2001)

	Lowest	Average	Highest	Related company	
	(in ¢EUR/kWh)			Lowest rate	Highest rate
High voltage transmission	0.86	1.27	2.04	Energie-Dienst/ KWL	AÜW, Kempten
Medium voltage transmission	0.62	1.45	2.78	RWE-Net, Dortmund	avacon aBL, Helmstedt
Low voltage distribution	0.66	1.85	3.50	Mainova, Frankfurt	Energie-Dienst/ KWR

Source: BWK (2001b), p.27; own calculations.
Note: Cumulative rates tend to be higher (lower) than the sum of the lowest (highest) rates.

Table 2. Cumulative electricity transmission and distribution rates, Austria (as of January 2001)

	Annual hours of utilization					
	1,000 hrs		4,000 hrs		8,000 hrs	
(in ¢EUR/kWh)	Lowest rate	Highest rate	Lowest rate	Highest rate	Lowest rate	Highest rate
110 kV (3)	1.51	3.42	0.86	1.46	0.66	1.28
10/30 kV (5)	2.62	7.63	1.59	3.68	1.42	3.21
Transformer station (6)	3.15	10.29	1.91	5.52	1.71	4.76
0.4 kV (7)	6.50	15.61	3.68	8.88	2.90	7.74

Source: WKOÖ (2001); own calculations.
Notes: Grid use charges in Austria vary by region (province); numbers in brackets denote the voltage layer.

In contrast, Austria has implemented the EU Directive 96/92/EC with an electricity act that was published on 18 August 1998 (Elektrizitätswirtschafts- und organisationsgesetz – ElWOG) and entered into force on 19 February 1999. The Federal law was concretised by complementary laws of the nine Länder, as well as two ministerial ordinances, one dealing with the principles of transmission pricing and the other with stranded cost compensation. Besides, the Länder laws focused on details of the promotion of renewable energy use, new power plant authorisation criteria, and public service obligations. In 2000 a new electricity act was published (ElWOG 2000). Among other changes (e.g. installation of a clearing house, labelling obligation), an important aim was to reduce the existing imbalance in market exposure faced by the various Austrian regional electric utilities (ranging from some 5-80%).

Regulatory issues – levelling the playing field

Germany, the largest electricity market in the European Union, is the only EU member country that still sticks to a negotiated third-party access (nTPA) to the grid without a regulator. This offers, at least for a while, some leeway for the transmission and distribution grid operators to charge excessive transmission fees and hence to reduce competitive pressure. At the same time, at least temporarily, it reduces the need for innovation and structural change. Three years after the market opening, rates for electricity transmission and distribution still vary quite substantially among the grid operators in Germany (Table 1). Electricity traders have been complaining about the large differences between (partly still unpublished) transmission rates, delays of wheeling contracts, and high measurement charges at the point of final use (Oehler 2001). One of the six large utilities, EnBW, has even called for a regulator (Wertel 2001). The German antitrust administration has stated that there is sufficient evidence that some of the observed wheeling and distribution rates are far above real cost and that unjustifiable charges for grid use are taken from traders and final consumers. Therefore, it is presently developing a concept for establishing fair rates for using the grid (E&M 2001a).

In contrast to Germany, an independent regulatory authority for the electricity sector (‘E-Control’) has been established in Austria by 1 March 2001. It has to monitor and regulate the 100% liberalised Austrian power market since 1 October 2001, when the new electricity act (ElWOG 2000) entered into force. This approach seems to be much more in line with the current stance of the European Commission, which has recently clearly indicated a strong preference for a regulated TPA (e.g. European Commission 2001). There is also hope that the regulator will harmonise the currently very heterogeneous grid-use charges (Table 2) in the near future, thereby reducing existing market distortions.

Impact on excess capacity – countdown of production monopolies

Surplus capacity of electricity generation before liberalisation was more than 17 GW in Germany alone (or around 20%) and the total surplus capacity within the EU was estimated to be in the order of 40–50 GW. In Austria, due to the high reliance of electricity generation on hydropower, surplus capacity in a particular year depends strongly on the annual amount and seasonal distribution of rainfall, which creates a need for higher reserve capacity and makes it harder to come up with a concrete number.

Because of the different speeds and points in time of the market opening in the EU member countries, and the open time schedule for the accession of the Central European countries, the impact of market liberalisation on excess capacity is somewhat difficult to evaluate. However, it is not only the timing of the opening and extension of the power market which influences the phasing out of excess capacity, but also the

- age structure and economic performance of existing power plants, which may induce investments in new and highly efficient generating capacity (e.g. 10 state-of-the-art generating plants with a total capacity of 3,900 MW were added to the German stock in 2000 alone);
- intensity of competition in particular regional or national markets;
- market structure and power, which also depend on the companies’ size (financial flexibility), type of power plant (high financial back-ups of companies running nuclear power plants), and ownership (e.g. EdF with no specific profitability obligations, mu-

nicipal electric utilities (Stadtwerke) traditionally co-financing other public services, e.g., city transportation and swimming-baths);

- price policies of the utilities, differentiated by customer groups;
- development of new entrepreneurial activities by existing utilities (e.g. to aid customer binding), new foreign energy companies entering the domestic market, or specialised companies (e.g. contractors for co-generation plants);
- new recent technological developments, such as information and communications technology, remote control of electricity generating plants, micro-turbines, and in the future also fuel cells; and
- national or regional policy measures for developing renewables and/or co-generation, such as those aiming at climate change mitigation and/ or technical innovation (e.g. the German buy-back rate law for renewables, and most recently for co-generation and fuel cells).

Given this complexity, it is not trivial to trace back the direct impacts of the electricity market opening at the national level. But the net phasing out of surplus capacity is substantial anyway: In Germany, for instance, two of the major remaining companies announced in summer 2000 to phase out around 10,000 MW of generating capacity, some of which is planned to be kept in a conservation status. Two nuclear power plants, a rather old plant in Stade and a new and practically never fully operational plant near Mülheim-Kärlich, with a total capacity of 2,000 MW (or almost 10% of the nuclear capacity in Germany), will be phased out by 2003 (see E.ON Energie Presse 2000; RWE 2000; VDEW 2001, among others).

The association of the German electricity sector (VDEW) comments on these changes by emphasising the optimisation process the sector has to undergo. Companies no longer plan their own maximum reserve capacity, but try to co-operate. In other cases, mergers contribute to reducing the reserve capacity. VDEW (2001) also emphasises that the planned and already realised reduced capacities of electricity generation will not reduce the traditionally high level of security of electricity supply.

In Austria the development has been less dramatic, given the dominance of hydro power stations for which the investment cost with few exceptions (like the run-of-river plant Freudenau) have been recouped during the time of a regulated monopolistic market structure, so that they are currently very cost-competitive. The planned shut-down of the (hard-)coal-fired thermal power plants at St. Andrä (124 MW), Korneuburg (285 MW), and Zeltweg (137 MW) in the short run and of Voitsberg (330 MW; lignite) in the medium run has not only been motivated by their relative cost-inefficiency, but also been driven by the marketing desire of the Verbundgesellschaft to offer and sell still 'greener' electricity in the future.

Impact on electricity prices – the expected fruits

Due to the enormous market pressure and the induced rationalisation, average electricity prices have been substantially reduced since the beginning of the market opening in Germany (and even before 1998 in anticipating the liberalised market: 1991/97 industrial consumer prices declined by 20%, residential consumer prices by 5%; see Jochem/Tönsing 1998; BMWi 2000). The producer prices have almost halved within three years, reaching average figures in the order of 1.5 $¢_{EUR}$/kWh at the Leipzig Power Exchange (LPX). These prices did in many cases not even cover the variable costs of electricity generation and may have been possible only by the revenues gained from financial assets of the large utilities. The consumer prices charged depend on the producer prices, the rate for using the transmission and distribution grid, taxes/levies imposed, and the sales margin. The rates for using the grid, which depend on the voltage and time of use over the year, vary substantially among the companies, with average values of, e.g., in Germany 1.3 $¢_{EUR}$/kWh at the high voltage and 4.6 $¢_{EUR}$/kWh at the low voltage level (including the upstream rates).

The Dow Jones VIK Price Index for industrial consumers shows an interesting development of the electricity prices between the opening of the German power market in April 1998 and June 2001 (Fig. 1):

- At the opening of the market, industrial consumer prices among the large generators only differed around 1.2 $¢_{EUR}$/kWh, whereas they differ by more than 2 $¢_{EUR}$/kWh since January 2000. Theoretically, one would have expected a decrease of the difference under competitive conditions.
- Average electricity prices in Germany declined by some 2 $¢_{EUR}$/kWh between 1998 and early 2000, stagnated during most of 2000, and seem to fluctuate since early 2001 with some tendency to increase again.

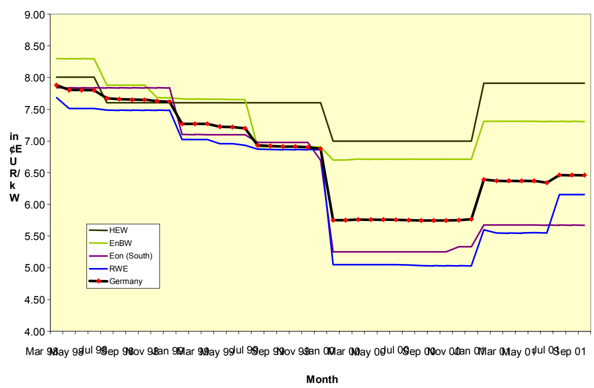

Fig. 1. Industrial electricity price development in Germany, Dow Jones VIK-Index, 3/1998–9/2001

Source: BWK (2001a), p.10

Hence there is some indication that the transition phase of liberalisation, as far as price adaptation is concerned, may last no longer than 4–5 years in a country with full market opening. Industrial customers have greatly benefited from the price decline since the market opening, whereas retail prices for private households have been reduced only slightly in Germany (partly as a result of the eco-tax, which was introduced in 1999 and raised to 1.5 $¢_{EUR}$/kWh by 1 Jan 2001; similarly, in Austria the savings of the captive consumers have been considerably reduced by the rise of the electricity levy from 0.73 to 1.5 $¢_{EUR}$/kWh (ATS 0.1 to ATS 0.2/kWh) by 1 June 2000 as one of the fiscal measures taken to reduce the budget deficit).

Impact on utility company structures – search for the optimal size

The major objective of the liberalisation of infrastructures with natural local monopolies is to introduce competitive structures and to increase market transparency in order to avoid economic inefficiencies and extra profits of local or regional monopolies. Competitive behaviour in the deregulated electricity market was expected to lead to rationalisation of labour and capital, but of course it also leads to concentration (e.g. mergers & aquisitions, co-operation agreements) of the electricity generating and distributing companies in search for economies of scale and of scope. Some sceptical energy economists have argued that the liberalisation of electricity supply could eventually lead to an oligopolistic market structure with similar prices and *de facto* dependency of most electricity consumers from electricity suppliers, but within the changed context of a much narrower set of business objectives, as compared to the broader objectives and perspectives of local and regional utilities before market liberalisation. Presently, one can observe the following changes in market structure of the German supply market (see also Table 3):

- The number of large generating and high voltage transmission companies (Verbundunternehmen) decreased from nine in the early 1990s to six in 2000 and is likely to diminish further to four by 2003 (two thirds of the German electricity generation capacity is owned by RWE and E.ON alone).
- The number of regional distributors decreased from 80 in 1997 to 34 in 2001, and is likely to go down to less than 25 within a few years; the merger & acquisition process is still going on (five regional companies in Bavaria will be merged to one company before the end of 2001).
- The number of municipal electric utilities (1997: 800) is decreasing, though no official statistics exist and the recent numbers published in various journals differ strongly (ranging from no changes to a decline by 230).

Table 3. Structural change due to liberalisation in the German electricity industry, 1997-2005

	1997	2001	2005**
Type of company	No. of companies		
High voltage generation and transmission*	8	6	4
Regional distributors	80	34	< 25
Local distributors, municipal utilities	800	570 to 800?	< 400

Data sources: Schiffer (1999); ARE (2001); E&M (2000); estimates by CEPE. * Verbundunternehmen; ** estimate.

Looking into the next few years it seems rather likely that the number of companies at all three levels of electricity supply in Germany will at least halve. But more importantly, the ownership of the formally independent regional and local distributing companies is changing from public to private, and often shifts to the big European players in the electricity and gas markets. Going Europe seems to be a must for the big and formerly national players, and the list of examples becomes longer every week: e.g., recently the German EnBW has contracted 600 GWh of electricity per annum with Austrian customers, and E.ON is a top favourite to become a new shareholder of EVN, the utility of lower Austria. Verbund seeks access to final consumers abroad by delivering electricity to German Stadtwerke, while RWE has set a foot in the south of Austria (by buying 49% of KELAG via the Carinthian energy holding company). Meanwhile, the new joint venture EHP (European Hydro Power) between Verbund and E.ON will create a ‘new’ major European player in the provision of green power (NZZ 2001).

Most of the price reductions could be achieved by severe rationalisation of labour. Employment in the German electricity sector declined by 18,000 between 1993 and 1997, and between 1997 and 2000 by some additional 64,000 (i.e. 25%), whereas electricity production stagnated from 1997 until 1999. In Austria, the number decreased from some 30,400 by the end of 1990 to 24,000 by the end of 1999 (end of 1997: 26,500). This rationalisation may have its own social cost as, for example, most of the demonstration projects and free consulting services offered to small customers regarding a more efficient use of energy have been stopped. Other options of cost savings, such as diminished technical redundancy in the grid, reduced maintenance, and phasing out of power generation plants have also been taken up by the companies.

Impact on CHP and power from renewables – importance of adequate boundary conditions

Co-generation of heat and power (CHP) has a long tradition in the two countries studied, both in industry as well as in district heating. The low electricity prices for large industrial customers during the last few years, however, led to a 20% decline of co-generated electricity in the German industry between 1995 and 1999. According to a mid-2000 survey, the declining trend is continuing (Vierthaler 2000). The decline was most pronounced in the steam turbine technologies (-30% for back pressure turbines, -23% for extraction condensing turbines), whereas gas turbines (+10%) and engine-driven plants (+55%, though from a low level) experienced considerable growth (VIK 2001). The decline of co-generated electricity was also influenced by structural changes towards less energy-intensive industries. In contrast, the share of co-generated electricity in Austria increased by 22% to 14.3 TWh (equivalent to 24.8% of total electricity generation) during the same period (Eurostat 2001).

In Germany, on 11 May 2001 five associations agreed upon a compromise on a bonus system for electricity produced by co-generation and fed to the grid (voluntary agreement, approved of by the government). The bonus (1.5 to 1.25 ¢$_{EUR}$/kWh) and its duration (4–8 years) depend on the construction year of the CHP plant and the year of re-powering. It is claimed in the declaration that the bonus will contribute to an additional electricity production of some 55 TWh p.a. in 2010, cutting Germany's CO_2 emissions by some 11 million tonnes. The cost of the bonus is estimated to be about EUR 4 billion and to increase electricity prices for all customers by 0.1 ¢$_{EUR}$/kWh (E&M 2001b). Electricity used within the co-generating companies will not be eligible for the bonus, an important drawback relative to a quota and a certificate system that the German government originally wanted to implement as a market-oriented instrument.

In order to maintain innovative developments in the use of renewable energies, which commonly exhibit substantially lower external cost, the German parliament decided upon a law on buy-back rates for electricity from renewables in 1999 (EEG 2000), that guarantees certain feed-in prices for electricity based on renewables, and that particularly helped to sustain the rapid development of wind power plants in Germany. In Austria, feed-in tariffs have been used for quite some time by the provincial governments for the promotion of renewable energy technologies. The new electricity act (ElWOG 2000) contains a rather ambitious, increasing quota target for non-hydro-based renewables (1% by Oct 2001; 2% by 1 Oct 2003; 3% by Oct 2005; 4% by Oct 2007, based on final electricity consumption) and, in combination with a tradable certificate system, another consumption-based fixed quota target of 8% for small-scale hydro power (≤ 10 MW). And while the feed-in law for electricity from renewables was extremely successful in supporting wind energy diffusion in Germany, it contributed an extra 0.2 ¢$_{EUR}$/kWh to the bills of the electricity users.

Influence on cross-border electricity trade volumes – profits and troubles?

Concerns have been raised that the opening of the electricity market in Western and Central Europe may at least in some countries induce major changes in the electricity trade balances. Particularly, imports from France and Central European producers, or even cheap electricity from Russia, have been identified as a potential threat to German and Austrian electricity producers. The capacity of the ten accession countries Bulgaria, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland, Romania, Slovak Republic, and Slovenia accounts for approximately 20% (112 GW) of the power generation capacity of the EU-15 in 1999 (561 GW). Most of the Eastern European countries have excess capacities, albeit most of the capacity is neither very efficient nor very reliable, and in most countries (except perhaps in the Czech Republic) rather polluting.

A most recent analysis on the future development of cross-border electricity trading patterns in Germany, however, concluded that net imports may actually increase up to only 8% in 2005 and can be expected to decrease thereafter (Bradke et al. 2001). In line with this and other studies (e.g. Prognos/EWI 1999, 2000) and our own assessment we do not expect the German or Austrian power trade balance to deteriorate significantly. There are several reasons: transmission losses are significant. Over time the age structure of the power plants in Europe will converge significantly, making foreign trade of base and medium load power less attractive. Moreover, due to the continued integration of the European power market and the environmental obligations to be adopted by the accession countries, similar generation cost in the Central European countries can be expected. Due to a large potential in hydro-based peak power production, Austrian generators, just like the Swiss, are in a favourable position in this respect. The possible increase in net imports will be influenced both by increased imports and by reduced exports. Also, import levels in the coming decade will strongly depend on actual electricity demand. Electricity trade patterns are also limited by current cross-border transmission line capacities, which due to their high capital intensity are unlikely to be substantially increased in the near future. Moreover, traditionally importing countries such as Italy (from France) are not likely to increase their generating capacity above their electricity demand growth. Finally, the risk inherent in building long-distance transmission lines from Eastern to Western Europe is further aggravated by the yet unknown diffusion rates of the fuel cell technology in Western and Central Europe over the next 20 years ('virtual power plants').

Conclusions

The introduction of competition and the establishing of a fair level playing field (non-discriminatory market access, transparency) are cornerstones of a successful liberalisation policy. However, the pre-liberalisation structure of the industry, the institutional framework and political circumstances, the domestic power resources available, and the aptitude for swift adjustments of both industry and regulatory bodies seem to be often neglected in analyses and discussions. From this viewpoint we could identify the following important trends in our analysis:

- The surplus generating capacity of some 10–15% will disappear within a few years; capital-intensive, large-size generating technologies (e.g. nuclear or hydro plants), although currently in a quite comfortable position, have less chances in the future due to the high investment risks in at least partially saturated markets, innovative technologies (e.g. fuel cells, micro-turbines), and decentralised renewable electricity generation (e.g. wind, geothermal, biomass) with relatively low externalities;
- Without political intervention, co-generation is likely to suffer in the adaptation period because of very low industrial electricity prices based on short-term marginal cost calculations (sometimes lower than the variable cost of CHP), back-pressure steam turbines are specifically endangered; in the longer term, CHP may have a

brighter future, envisioning a widespread use of fuel cells ('virtual power plants');

- The transition phase in an instantly opened electricity market with some overcapacities may be around 4–5 years, before prices tend to be based again on long-term marginal cost, whereas concentration processes (and thus the need for consolidation of business units) will last much longer;
- Companies with large financial resources, particularly nuclear power operators, can develop substantially more market power and benefit more from the liberalised market than small utilities (economies of scale, purchase power); further, it is not clear whether antitrust bodies will in the long run be able to effectively avoid market power abuse by new oligopolistic market structures;
- The substantial rationalisation of labour (by at least one third of the workforce under monopolistic power generation and retail markets) occurred at the expense of energy efficiency/saving consulting activities for small consumers, cross-financing of non-profitable public services, and reduced RD&D spending;
- Offers for energy services, such as contracting for bigger customers, will continue to be drastically increased to bind large consumers for longer periods to electricity (and gas) deliveries.

After the breakthrough at COP-6bis in Bonn and COP-7 in Marrakech, respectively, to salve and in 2002 to eventually ratify the Kyoto Protocol, present activities of CO_2 mitigation are likely to be reinforced, and more energy-efficient and less carbon-intensive electricity generation and use will receive increased attention in the future. This in turn may have a substantial impact on the utilities' service portfolio, on the prospects for decentralised power generation options and efficient electricity use, and the export opportunities for highly efficient technologies to industrial and developing countries ('leapfrogging'), especially to those currently in the process of opening their electricity markets.

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Options and potentials for European electricity imports and exports: a German perspective [25]

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Keywords. Electricity Trade, Interconnected Networks, Electricity Production, Forecast, Europe

Abstract. In this paper some focal points with major influence on the power exchanges are described. The technical restrictions imposed to international trade of electricity by the networks and the costs for power transports are discussed. Further, the electricity sectors of four EU countries and three Central European countries are characterised concerning the market structure, the main energy sources for electricity production and the historical international exchanges. The marginal costs of power generation are calculated for the years 2000, 2005 and 2010 to make projections of the future electricity exchanges using the example of Germany.

Introduction

The EU Directive 96/92/EC had an enormous impact on the electricity markets all over Europe. Former supply monopolies are transformed into active market players, a development still carrying on. An increasing part of the electricity consumers can choose their supplier which may be located abroad. In some countries even the household consumers can buy their electricity from the supplier of their choice as of the first minute of liberalisation. In many countries, the new market elements led the incumbents and the newcomers on the markets to a tough price competition in the struggle for keeping their market share and for gaining new customers. The opening of the market has also changed the relation between the utilities fundamentally. The international exchange of electricity which formerly based on long term contracts is mutating into a fiercely contested market with low margins.

Company structure

The electricity industry was organised in quite a varying manner across the Europe. Whereas in several countries like for example in France or in Central European countries, a single, state owned utility was serving the whole market, in other countries like Germany, the market was divided among regional suppliers, which could be as small as municipal utilities serving not more than a couple of thousands of customers. The end of the monopolies induced a long series of organisational changes. First of all, the vertically integrated utilities had to be broken up. However the break up could also mean just to reorganise the companies internally, without creating truly independent entities. The change of the electricity industry was not so much dominated by this break-up, but more by the mergers and acquisitions that took place since and are still continuing. EdF from France for example bought utilities all over Europe like London Electricity or ECK of Krakovia. In Germany for example, the new player E.On emerged out of the two players Veba and Viag.

The interconnected network

A major part of Europe is integrated in the interconnected power grid of the UCTE already today (See Fig. 1) and DC-connections to the networks of Great Britain and of Scandinavia enlarge the area, in which imports and exports can be done. As a consequence of the destruction in Bosnia-Herzegovina and in Serbia, the south-eastern part of the UCTE network had to be disconnected from the main part. Up to date, the connection could not be restored, but approaches are made to reunite the networks by integrating the networks of Bulgaria and Romania.

In 1995, the networks of the eastern part of Germany and of the CENTREL formed by Poland, the Czech Republic, Slovakia and Hungary were synchronised with the UCTE. The exchange capacity between the UCTE and these countries increased to at least the double of the level it had before, which was limited to the transfer capacity of three DC-coupling stations. The transfer capacities to the Ukraine and to Russia (or Belarus respectively) are only very small today. The high voltage lines of the former unified energy system of the Eastern Block are still existing but they can not be used as long as the networks are not synchronised. Therefore only the capacity of several blocks of the power station Burshtyn which are synchronised with the UCTE network is transferred to Poland and Slovakia. In order to achieve a major increase of power exchange between Ukraine and Russia on the one hand and the UCTE-countries on the other hand, either the grids of the former two countries had to be synchronised with the UCTE or additional DC-couplings had to be installed. Both of these options demand high investments, especially a possible synchronisation, because the network design of the UCTE grid and of the former Soviet Union's grid differ in several important fields.

Limited transfer capacities

Transfer capacity is limited not only to the neighbouring networks in Eastern Europe, but there are also bottlenecks along the borders in the interior of the UCTE-area and to the neighbouring networks of Great Britain and to Nordel. Examples are the connections between France and Italy, Germany and the Netherlands or Germany and the Centrel (in this case Poland and the Czech Republic). At most of these points, where congestion occurs, auctions were held by the network operators to allocate the transfer capacity in a transparent way. The prices paid at these auctions reached as high as € 95,000 per MW (see Table. 1). At the French-Italian border auctions were planned as well for 2001 but could not be held as they were contested at Italian courts. The transfer capacity was then allocated following a scheme which put an advantage to the holders of long term contracts. This solution is to

[25] This paper is based on the result of study prepared by the authors for the German Federal Ministry of Economy and Technology.

criticise as it obstructs the development of market structures

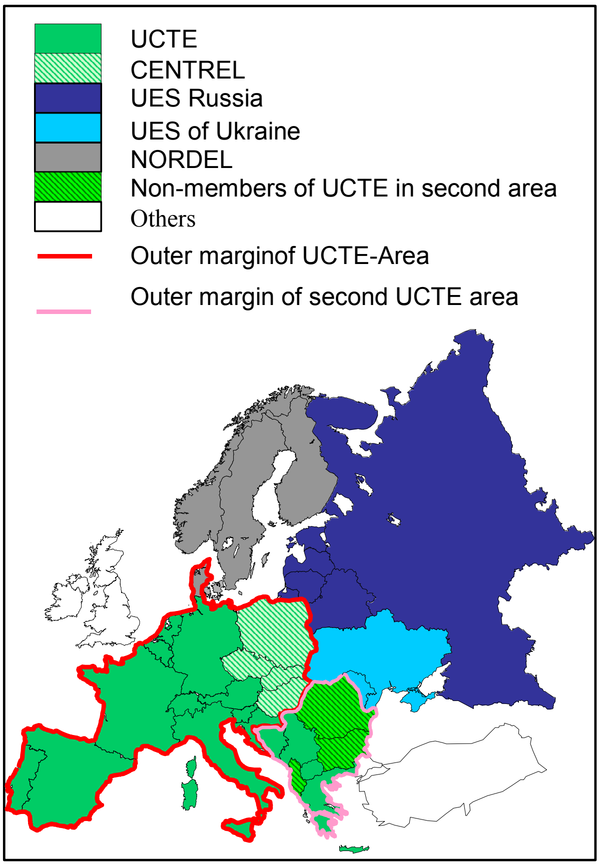

Fig. 1. The main interconnected networks in Europe

The interconnected network in Europe allows power exchanges only to a certain degree. (A prognosis for the transfer capacity is published by ETSO every half year.) So, the construction of new power lines could promote the international power exchanges and help in developing the market. Actually, only few actions for new lines are undertaken, and these concentrate mostly on the construction of submarine cables. The construction of new terrestrial lines is very difficult, as the environmental concerns are very high and often there is strong opposition from local stakeholders against such projects. Another problem is imposed by the fact that the electricity traders, who have the highest interest in the augmentation of the transfer capacity work with contracts that usually are not longer than three years, a timeframe in which the investment into new power lines can not be paid back.

Table 1. Results of auctions for transfer capacity

Border and direction	Network operators	Results of auctions in €/MW
Pl→D	PSE, VEAG	25.017
D→Pl	PSE, VEAG	--
CZ→D	CEPS, E.on	4.380
D→CZ	CEPS, .É.on	40
DK→D	Nordel, E.on	14.200
D→DK	Nordel, E.on	2.095
NL→D	Tennet, RWE	750
NL→D	Tennet, E.on	307
D→NL	Tennet, RWE	92.203
D→NL	Tennet, E.on	95.484
F→GB	EDF, UKTSOA	65.832
GB→F	EDF, UKTSOA	

Data: E.on, 2000, TSO, 2001, Smith 2001

Transmission tariffs

To date, there is no European agreement concerning the costs for international power exchanges. The network access still has to be negotiated bilaterally with every grid operator along the way of any transaction. The European Transmission System Operators association (ETSO, 2000) had formulated a proposal for a fixed international network access fee that would have had to be paid once for the first border crossing and opened the way up to final destination. The proposed amount of 2 €/MWh was not accepted as the electricity traders judged it as too high. Negotiations were continued on a concept favoured by the European Commission that allocates at least a part of the costs to the final users of electricity and leaves a reduced fee to the electricity trade (DVG, 2001). On the one hand, reducing the costs for the power transmission would promote the international electricity market, on the other hand, it would set a misleading price signal favouring long distant transports at the expense of power generation close to the consumption.

European countries' power industries – examples

France

The electricity industry lies in the hands of the state-owned Electricité de France. Next to the EdF there are only few small electricity generating companies. The high integration of the electricity supply originates in the French tradition of a high responsibility of the state for the public services. The French government decided to follow the minimum requirements of the European electricity directive. The market will be fully opened by 2006. EdF strongly defends its market position and stated that in the year 2000 only five per cent of the eligible customer chose a different supplier (EdF, 2001).

Power generation in France relies heavily on nuclear energy. The share of this energy source grew from less than a quarter to almost 80 % in the middle nineties. Apart from nuclear power hydropower has a share of around 15 %. France is the largest exporter for electric energy in Europe (62 TWh in 1999; UCTE, 1999). Compared to the inland use, France possesses a high surplus capacity for power generation. However, taking into account the long term contracts, EdF has to fulfil, the generation capacity seems to touch its limits in peak load situations in winter times.

Italy

Already beginning of the nineties, plans for the privatisation of the state owned electricity company ENEL, which is the major producer of electricity in Italy (1997: 63.5 % of the Italian demand were produced by ENEL) have existed. But only with the European directive in the background the idea to end the monopoly could become reality. As of 2003 no supplier may cover more than 50 % of the electricity demand. The ENEL will be broken up into a holding of a production company, a transmission company and a distributor.

The generation of electricity in Italy is mainly based on fuel oil and natural gas. These two energy sources make up around 70 % of generation with a growing share of natural gas (Unipede, 1998). Italy stopped the use of nuclear energy after a referendum in 1987. The use of the comparatively expensive energy sources oil and gas in medium aged and older power stations with lower efficiency leads to high costs of power generation in Italy. The cost structure and the decision not to use nuclear energy made grow the electricity imports to Italy in the last decade. Italy is the largest importer of electric energy in Europe (42 TWh net imports in 1999; UCTE 1999).

The Netherlands

In the Netherlands, the electricity industry was reorganised already in the eighties in order to introduce some market elements. Production and distribution of power were separated strictly. The reorganisation led to a concentration of the industry into four generation companies and around 25 distributors. Apart from a few exceptions, only the generation companies were allowed to buy electricity from foreign suppliers. The market elements had only limited impacts, as there was no variation in prices and the relatively small distribution companies could not organise a sufficient market power against the supply monopoly of the generation companies organised in the association SEP.

With the European directive the transformation of the electricity industry was continued. The market is opened stepwise until 2007, but already 2002, around two third demand can chose the supplier. Of the four generation companies three have been sold abroad. In Amsterdam, the power exchange APX was founded, contributing to a transparent market.

The most important source of energy for power generation is natural gas with a share of slightly below 60 % (1998: 58 %) followed by coal (around 30 %). The Netherlands are another major importing country for electricity. In the recent years the import balance never fell below 10 TWh, but it showed strong variations.

Germany

The electricity industry, which had no market elements before 1998, was opened in one big step giving the right to choose the supplier to every customer. Unexpectedly, the competition arose not only in the segment of big and medium sized industry customers but also in the field of private households. The German utilities started a big round of mergers to form bigger and potentially stronger players on the newly formed market. There are two major players, RWE and E.on. EnBW is the third of the bigger players but considerably smaller. There will be probably a fourth big player, formed out of utilities in the north east of Germany but the outcome of the merger of the utilities of Hamburg and Berlin and of the VEAG just faced a setback. The market transparency rose significantly with the start of operations of the power exchanges LPX and EEX, which recently merged.

Power generation relies mainly on nuclear energy, hard coal and brown coal. None of the other sources of energy reaches the ten percent margin. Still one can note that the share of natural gas rose steadily over the last decade. In the future, the agreement between the federal government and the electricity industry to phase out the use of nuclear energy will have a major influence on the electricity industry.

Imports and exports of electricity each are in the range of 6-8 % of the consumption. The balance of the exchanges always was lower and fluctuated between net imports and net exports (UCTE, 1999).

Table 2. Characterisation of the four western countries analysed

	F	I	NL	D
Electricity consumption 1998 (TWh), final energy[1]	395	261	95	488
Projection for 2010[2]	478	335	117	526
Import/export balance 1998 (TWh)[3]	-57	41	12	-1
Market opening in 2000	30 %	30 %	33 %	100 %

[1] IEA, 2000, [2] European Commission, 1999, [3] UCTE, 1999

Poland

The Polish electricity industry is still dominated by the big national utility PSE. But still, there are already quite few market elements in the industry. By 2000 around 43 % of the internal power demand was open to the market (DIW, 2000) and the doors of the Polish energy exchange (PPX) opened in the same year. Until 2006 a complete opening of the market is foreseen in the energy law of 1997. Several regional utilities have been sold to foreign power companies. Even with the described market elements in place, there is only very low competition as many power stations have long term contracts with the national electricity company PSE. These contracts were made secure the investments in the modernisation of many older coal fired power stations. The traded volume at the PPX therefore is still low. Market access for foreign suppliers is not guaranteed but not excluded either.

Hard coal and brown coal stood for more than 95 %of the energy for power generation. Nuclear power has never been used in Poland. Even with the modernisation of power stations in the last years, in Poland still exists a big stock of older power stations with higher emissions.

Poland is a net exporting country of electricity. Most of the exports are directed to the Czech Republic. At least part of the exports are transits to West-European countries. The exchanges are also controlled by the regional distribution of the power stations in Poland, the Czech Republic and Eastern Germany, which influences strongly the physical flow of electricity in this region. At least part of the Polish exports to the Czech Republic are transits into western Europe.

The Czech Republic

The Czech electricity sector has already been transformed partially and market elements are in force. The market power of the national energy supplier CEZ which produces around 70 to 75 % of the electricity is still predominant. Next to the CEZ, there are producers which own the CHP-stations. These power stations, providing the heating energy for bigger cities, have been privatised already in the beginning of the nineties. On top, there are several independent power producers on the supply market (Strmiska, 1999). There are eight regional distribution companies, which have to buy part of their demand from the national supplier CEZ at set prices. For the rest of their demand, they may chose freely the supplier which may be abroad.

The Czech electricity production relies strongly on brown coal, with a share of over 50 %. Second in the order of importance is nuclear energy, which will increase its share with the full operation of the Temelin power station. According to CEZ, the coal fired power stations have been modernised already and do fulfil the environmental requirements for the accession to the European Union. Although still very low, the share of natural gas for power generation is about to increase.

The foreign trade of electricity is of high importance. The Czech Republic is a net exporter of electricity, although there is a serious amount of imports especially from Poland. Main destinations for exports are Germany and Austria.

Slovakia

In Slovakia, the transformation of the electricity sector started later than in most of the other countries in Central Europe. First steps were made in 1998 with a new formulation of the energy law (DIW, 2000). In order to be able to fulfil the accession criteria to the European Union, the energy policy was reviewed again in 2000. The single buyer system, which was set out in the law of 1998 should be transformed into a network access system. Since beginning of 2001, about 20 % of customers can choose their supplier amongst domestic companies. The access of foreign suppliers to the Slovak electricity system is not foreseen in the medium term.

Nuclear Energy is the most important source of energy for electricity production in Slovakia with a share of 47 % in 1999, followed by Coal and hydropower. The share of nuclear power will probably continue to increase, as the Bohunice power station, commissioned end of 1999, will unfold its influence only in the following years.

Slovakia used to be an electricity importing country. With the commissioning of the Bohunice power station, the balance of foreign exchanges will change to net exports of power.

Table 3. Characterisation of the three Central European countries analysed

	PL	CZ	SK
Electricity consumption 1998 (TWh), final energy[1]	112	52	21
Projection for 2010[2]	152	69	31
Import/export balance 1998 (TWh)[1]	-4,2	-2,4	4,0
Market liberalisation in 2000	43 %	-	-

[1] IEA, 2000, [2] Unipede, 1998

Projection of generation cost

Market background

In several countries, including Germany, the utilities kept a high amount of surplus generation capacity. In the time of the monopolies, this surplus was no burden and could be used to keep a considerably high power quality. Non-profitable power stations could be supported in vertically integrated companies.

The quickly emerging markets and the price competition pushed down the wholesale prices for electricity to marginal costs of generation in most of the load situations. As a consequence, many generating companies started to shut down power stations with a high cost structure in order to decrease the losses that could no more be supported by other parts of the business.

The structure of power generation in the European countries plays a major role in the actual wholesale prices for electricity. In Germany, the prices dropped down to the costs of a depreciated coal fired power station. In Italy, the prices are considerably higher because there, many older less efficient oil and gas fired power stations set the marginal cost in many load situations. The shutting down of capacity and the repowering of existing power stations and several new installations lead to a gradual change in the cost structure.

Costs of generation

Using a database with power station data from the European Countries, the marginal costs of electricity generation in the single countries were calculated. These are a good indicator the competitiveness of the electricity industry in the European market. The database, provided by a manufacturer of power stations, contained data of five year age classes of different types of power stations. Further technical data had to be introduced, e.g. concerning the availability and the average efficiency of the power stations of a specific type and age class. Here mainly the IKARUS database was used (Stein u. Wagner, 1999). Further assumptions had to be made for the fuel costs. The electricity demand was used to calculate the load for a typical average winter day load situation. The data of UCTE (1999) and of Unipede (1998). The demand was assumed to be inelastic in respect to the supply price. As the calculations should represent the short-term price setting, this assumption will not impose a major error to the results.

The results shown in Fig. 2 reveal clearly the cost differences in generation in the different countries.

France with its high nuclear capacity has very low marginal costs in the area of 1 €-Cent/kWh whereas Italy has the highest Prices in this group of countries in 2000. In this year, Germany with marginal costs just over 2 €-Cents/kWh lies in the mid range but climbs into the upper cost region in 2005 owing to the fact that several power stations will be taken of the grid, which do not reach enough operation hours with positive margin under market conditions. The calculation results, with modest estimations for the growth of real fuel prices, show little changes in the marginal costs in four of the seven analysed countries. The existing capacity is still sufficient to fulfil the domestic demand within the coming decade. In Poland, the shut down of older capacities and the projected growth of the electricity demand lead to a rise in marginal costs at the end of the period.

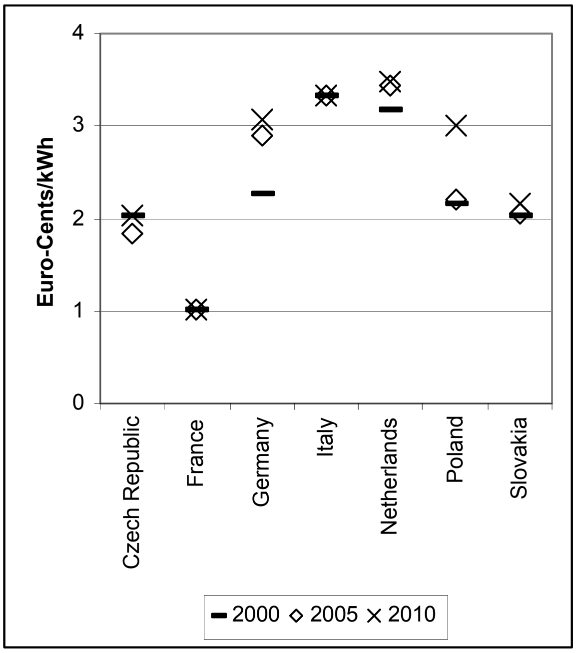

Fig. 2. Marginal Costs of Generation in seven European Countries

Future international exchanges of electricity

The liberalisation of the electricity markets has changed the structure of the industry strongly. But still the market opening has not yet led to a massive switch of end-use customers to foreign suppliers. Best example is France where the incumbent EdF defended its market successfully up to date.

But the cost differences in generation and the resulting price differences on the wholesale markets are a motor for a continuously growing international exchange of electricity. The limits to this market are set by the network capacities, which out of today's perspective will not be expanded in the coming decade significantly.

The price development in the German market and the tough competition will probably lead to increasing imports of electric power to Germany and to a demand of exports. It is very likely, that independent power producers will try to find access to the markets of the Netherlands and of Italy, both of which were main importers in the last decade. This will increase competition for German exports to the neighbouring Netherlands and set free generation capacity which was used to settle demand in Italy for possible exports to Germany. The more or less balanced foreign trade with electricity of the past will probably change into a import surplus which could grow to an import surplus of as much as 30 TWh per year in the period between 2005 and 2010.

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Session 2: The Internal Energy Market: Implementation of the EU Directives in the Accession Countries

Rapporteur's Summary by Eugene D. Cross, ECN Policy Studies, The Netherlands

Session Two focussed on the developments in electricity and gas liberalisation in four accession countries – Hungary, the Czech Republic, Poland and Romania – in order to reveal the progress and obstacles with implementation of the Electricity and Gas Directives in a more specific country context. The first two speakers were the respective regulators from Hungary and the Czech Republic, namely Peter Kaderjak and Pavel Brychta, whose presentations were followed by an update on Polish developments from Mr. Bolesta from the Office of European Integration in Poland, and on Romanian developments by George Lavrov (ISPE-Romania).

In the first presentation, Mr. Kaderjak, director general of the Hungarian Energy Office (HEO), outlined the ownership, structure and regulation of the Hungarian electricity and gas sector, as well as the recent developments in Hungarian liberalisation measures. The Hungarian Electricity Act (which was passed in December 2001) provides the basis for introduction of competition. The new law will enter into force as of 1 January 2003, with a few special exceptions set forth in the closing provisions. In other words, development of electricity licences, codes and regulations will take place during 2002, and the market will open from 2003. Network access will be regulated, authorisations procedures will be used for new generation capacity (and not tendering procedures), and licence holders must unbundle their accounts. An independent system operator (ISO) has been established (MAVIR) with the task of controlling the unified transmission system and the entire Hungarian power system at national level. Its basic duties and powers are set forth in the Hungarian Electricity Act, and include tendering for network development, integration of electricity sales contracts and co-ordination of the execution of electricity sales, various planning functions, and the public acquisition, provision and regulation (in agreement with the HEO) of ancillary services.

The market opening process in Hungary is burdened by pre-existing long-term PPAs that were signed five years ago. These are difficult to unwind, and the government must determine how to press forward with their renegotiation. There is a question of whether the proposed consolidation of IPPs as a means of dealing with the PPAs is consistent with the Commission's interpretation of the EU state aid rules. The HEO will have to make a determination on this issue. Regarding the HEO he heads, Mr. Kaderjak stated that it is not completely independent, not now or never, given that he has never seen a "completely independent energy regulator".

Pavel Brychta, the Chairman of the Czech Energy Regulatory Office (ERO) presented the recent activities and principle work of the new regulatory body. The ERO, established as of 1 January 2001 as a separate authority distinct from the Ministry of Industry and Trade, has been enabled by law to support economic competition and protect consumers in those energy sectors where competition is not possible. The Energy Act stipulates that the ERO is an administrative office "having a special heading in the national budget". Furthermore, the Act states that the ERO "shall be headed by its Chairperson who shall be appointed, and may be removed, by the government" only on the basis of specific causes listed in the Act. The ERO has been empowered, *inter alia*, to lay down the general "rules to organise the electricity market", decide disputes over network access, approve the rules of operation of the TSO and DSOs, and "issue legal provisions for the regulation, negotiation, and control of prices in the energy area".

Following the presentations of the Hungarian and Czech regulators, the subsequent discussion focused on the abilities of the regulators and competition authorities to promote and sustain competition in the market. A distinction was noted between the *ex post* powers of competition authorities, which review transactions that have taken place or for which official (merger) notification has been made, with the *ex ante* tasks of regulators, which must monitor the level of competition in the market and approve requests of companies to undertake certain activities.

Mr. Cross observed that some countries, such as Britain, have established concurrent jurisdiction such that competition office and the sectoral regulators (e.g. the electricity and gas regulator OFGEM) can enforce the prohibitions of competition law using their concurrent powers. He pointed out that many of the accession countries have developed the relationship between their energy legislation and competition legislation (and the defined inter-relationship of their respective regulatory and competition authorities) by including cross-references to the competition legislation in their energy legislation. In Estonia, for example, there is a cross-reference in the 1998 Estonian Energy Act to the Competition Act's definition of enterprises dominating the market. In Hungary, cross-references to the Hungarian Competition Act can be found in each of the subsectoral energy laws. However, this is not the case in the Czech Republic, where the Czech Energy Act of December 2000 does not refer specifically to the Czech Act on Protection of Competition.

Mr. Bolesta presented his detailed assessment of Poland's compliance with both the Electricity and Gas Directives, focusing on anticipated legislative adjustments and other measures. He reported that a new energy act was under preparation to replace the 1997 Energy Act, and his prediction was for its adoption during 2002. The subsequent discussion addressed the level of actual competition in the Polish power market. Mr. Bolesta was asked about the actual number of customers who had switched suppliers, but this information was not available. However, he noted that 70% of the market is reserved under power purchase agreements (PPAs), and therefore only 30% of the market is at issue and under discussion.

Mr. Lavrov presented his paper on the evolution of the Romanian electricity market, reporting the creation of a wholesale power market in 2000 and "significant progress in deregulation of energy sector and in establishing a competitive electricity market." He also noted that two distribution companies are scheduled for privatisation.

The subsequent discussion addressed a mix of topics, as various priorities for discussion and research were suggested and addressed in the time available. Based on his discussion with other participants, Miha Tomsic suggested distribution tariffs as a topic, as well as special "social tariffs" for low-income consumers. It was acknowledged that further attention to the regulation of ancillary services was needed. The Commission's new proposals for the electricity sector do not mention whether such regulatory authorities should have the power to oversee ancillary services, which heretofore has been left to the discretion of the Member States to regulate. Without this, competition in the market may not develop sufficiently.

Mirek Maly (SCRI/Enviros – Prague) noted trends in the coal market and predicted that the coal sector would survive in the Czech Republic (where gas-fired CCGTs have reportedly had difficulty finding a market, and where coal-fired power is underpriced only by nuclear). Miha Tomsic provided an update on the future of the coal sector in Slovenia. In Slovakia, the most expensive electricity was reported to be coal-fired.

A final suggested topic was on security of electricity supply and the role of pumped storage capacity. A delegate from Slovakia noted concerns over the ownership of pumped storage, and a suggestion was made that the pumped storage facilities in Slovakia should be owned by the power distribution companies.

Monitoring the progress of the implementation of the EU Gas and Electricity Directives – Polish case

Krzysztof Bolesta, Office of the Committee for European Integration

Keywords. Electricity and Gas Directives, Unbundling, Tariff, Adjustment process, Third Party Access, Market opening, Legislation.

Abstract. The paper will present state of play of transposition of the Gas and Electricity Directives to the Polish law system. The paper is focused not only on legislative adjustments. It will also present other measures undertaken to match the EU requirements. The ultimate goal of the paper is to assess level of compliance and find major gaps. The next step is to propose the possible way to solve existing problems and close the gaps. The paper will present possible future for the energy markets in Poland with its advantages and disadvantages. Assessment what was already done and what still needs further attention is also of vital importance.

Introduction

Poland is on its way to the European Union. The adjustment process accompanies accession negotiations. It covers all fields of economy but the emphasis is put on the European Single Market regulations. One of the elements of this process is adjustment in the energy sector. A lot has been done in the last couple of years but some changes are still to be done.

Negotiations

Energy chapter negotiations lasted for almost two years. The chapter was provisionally closed on 27.07.01. Poland had two important problems. One was how to comply with Community legislation concerning obligatory stocks of crude oil and petroleum products. The second was the speed of opening of the Polish gas market. At the beginning Polish negotiators asked for two transition periods, 8 years to comply with oil stocks requirements and 3 years to reach required level of opening of the gas market.

After two years of talks with the European Commission it was agreed that Poland would have to build the required oil stocks capacity by the end of 2008. Poland agreed to withdraw its request for the transition period concerning the gas market opening after a number of analyses concerning situation on the Polish gas market had been made.

At the end of the day negotiations are concluded and the most important part of the adjustment process has already begun. The aim of this paper is to briefly present the state of play of Gas and Electricity Directives implementation in Poland.

Gas Directive

Structure of the Polish gas sector

Poland consumes ca. 12 bio. m^3 of natural gas. 4 bio. m^3 are extracted in the country and 8 bio. m^3 come from import, mainly from Russia on the basis of Jamal "take or pay" contract. According to official prognosis the natural gas consumption will increase to reach 22-27 bio. m³ a year in 2010.

The Polish gas market is controlled by the state owned monopoly enterprise Polish Oil and Gas Company (PGNiG). To match the Gas Directive requirements Poland has decided to introduce wide range of structural changes in the sector, which should enable better transposition of the Directive and introducing of real competition. To this end existing monopoly PGNiG will be divided into 6 independent undertakings:

- four distribution companies,
- one prospecting and extracting company,
- transmission company, which will manage gas stocks and existing long term contracts. This company will keep the name PGNiG.

The above-mentioned structure will be established as of 1.1.2002. At the end of the day, all the new companies are already registered and wait for assets transfer from PGNiG.

The next step in the sector restructuring will be privatisation. The prospecting and extracting company will be sold by public listing. Shares of 4 distribution companies will be offered to the chosen investors. They will be allowed to acquire the majority shareholds. According to the existing restructuring program, transmission company PGNiG will not be privatised within next 5 years. After this period decision about the future of the company will be taken.

It has to be stressed that the new structure will create a very good basis for introducing of the real competition to the sector. On this basis a good piece of regulation must be elaborated. The complex amendment of the Energy Law is already in the pipeline. Existing regulations are generally very good, but there are still some gaps between the Polish law and the Gas Directive.

Polish gas market regulation

The Polish gas market is regulated by two acts: the Energy Law and the Geological and Mining Law. Geological and Mining Law regulates the market of all natural resources extracted in Poland. In respect to the gas market it touches only on prospecting and extraction of this fuel. It sets safety requirements and regulates authorisation procedures for prospecting and extraction of natural gas. It was last amended in July 2001 and it is now fully compliant with the Gas Directive requirements. The 1997 Energy Law regulates remaining gas market issues and other energy market parts. It represents a major benchmark in the process of adapting Polish energy markets to market economy principles. It provides the necessary legal conditions for economic activity in the areas of fuels, electricity generation, transmission, distribution and trade, introduces TPA and sets the general framework for gradual market opening.

In the process of transposing the Gas Directive to the Polish law system secondary acts are also important.

- Regulation on tariff setting mechanism describes the conditions of tariff setting by market operators. It defines the TPA as the regulated regime, as the tariffs must be approved prior their entry into force by the regulator. This regulation includes also timetable for reaching the market prices free of cross-subsidies.
- Regulation on connection to the gas network sets the conditions for connection to the gas network.
- Regulation on the TPA regime sets the timetable for market opening for eligible customers.
- Regulation on diversification of gas supplies sets the rules of gas imports. It is so called “security of supply” regulation.

Market regulator

Poland fulfils requirements of the Gas Directive in this field. The Energy Regulatory Authority (ERA) was established in 1997, on the basis of the Energy Law. ERA is the energy market regulator. The office is responsible not only for natural gas market regulation but for electricity and heating markets as well. The competencies on the gas market are:

- granting authorisations for fuels production, gas transmission and distribution, trade and stocking;
- regulation of natural gas prices;
- quality control of the supplied natural gas;
- settling the disputes concerning connection to the gas network;
- co-operation with anti-monopoly authorities to promote competition in the gas sector;
- assembling information about the gas market and investments in the sector.

There is one gap between Polish legislation and the *acquis.* It is impossible to grant an authorisation either for transmission or for distribution. It could only be granted for “transmission and distribution”. This problem will be solved by the existing draft amendment of the Energy Law.

There is also a need to add to the competencies of ERA right to assemble information about the gas market and investment on this market as to transmit it to the European Commission. This amendment is also envisaged in the mentioned draft.

Tariffs

Tariff setting is regulated by the Energy Law and the Regulation on tariffs. At the end of the day cross-subsidy does still exist. According to PGNiG sources it will be abolished within 3 years. The timetable envisages 5% raise over inflation ratio in the first year and 15% raise in each of two next years. That should bring gas prices to the market level in 2004.

The ERA President approves all the tariffs, as the Polish TPA is a regulated regime. It is important, that if the conditions of the free gas market will be fulfilled, ERA President might resign from approving tariffs. It is consistent with the Gas Directive but not with the draft Directive, as the EC opts for fully regulated TPA regime for transmission and distribution. Poland has this fact in mind and any change of the Energy Law will be proposed if needed.

Third Party Access

Regulated type of TPA was introduced in Poland. The tariffs are regulated and the customers know the conditions and prices connected with the network access in advance. In this respect Polish law is fully consistent with Gas Directive. But as it was mentioned before, in special circumstances, ERA President might resign from approving the tariffs and this may result in transition to the negotiated TPA. This issue requires further attention.

At the end of the day 25 customers are eligible to choose the gas supplier. The problem is that the regulation on tariffs requires distant related tariffs and these are not present yet. In this respect TPA system is not working practically. The other hurdle is that PGNiG is still one vertically integrated monopoly and possibilities to switch the gas supplier are very week. This should change with 1.1.2002 as distant related tariffs will be introduced and the monopoly finally abolished.

The main gap on the way to European structures is the nature of Polish TPA. The free choice of suppliers exists, but it is restricted only for gas extracted in Poland. This is the major concern of market operators from EU countries. During the negotiations Poland asked for transitional period concerning market opening for imported gas, but finally decision was made to lift the barrier. Result is that TPA will have to be granted to all the market operators on the day of accession.

Opening of the gas market

The Regulation on the TPA regime includes the timetable of opening of the gas market. Table 1 shows both, Polish timetable and this envisaged in the Gas Directive.

Table 1. Opening of the gas markets in Poland and EU countries

Type of eligible customers	EU countries	Poland
Customers buying more than 25 mio. m^3	10 August 2000	1 July 2000
Customers buying more than 15 mio m^3	10 August 2003	1 January 2004
Customers buying more than 5 mio. m^3	10 August 2008	5 December 2005 - full opening of the gas market

It is easy to see that Polish timetable is far more radical and in contrary to the Gas Directive it sets out the final date of full gas market opening. It has to be stressed that Polish regulations are almost compliant with the Draft Directive[26]. The single gap here is to include into the eligible customers all gas-fired power generators. It is already envisaged in the Energy Law amendment.

Unbundling

According to the Gas Directive, the integrated natural gas undertakings are obliged to keep in their internal accounting separate accounts for their natural gas transmission, distribution and storage activities, and, where appropriate, consolidated accounts for non-gas activities, as they would be required to do if the activities in question were carried out by separate undertakings, with a view to avoiding discrimination, cross-subsidisation and distortion of competition. These internal accounts shall include a balance sheet and a profit and loss account for each activity.

In Poland cross-subsidisation still exists as it was mentioned before. In addition, the Energy Law provides only for keeping separate accounts (apart from consolidated accounts for non-gas activities). There is no obligation for gas undertakings to prepare separate balance sheet and a profit and loss account for each of the activities. This will be changed by the prepared Energy Law amendment. The additional advantage will be restructuring of the sector organisational structure, what was already described above.

Security of supply

Last but not least is the problem of security of supply. Poland bears in mind security of supply policy, which is nowadays one of the main concerns in the EU.[27]

The ordinance of the Council of Ministers of October 24, 2000 on the minimum level of diversification of gas supplies from sets the maximum level of gas supplies from one country. For the years 2001-2002 the level is 88%. For the next two years supplies from one country will diminish to 78% level to reach 49% in the year 2020.

To meet the ambitious goals set by the regulation Poland is diversifying its sources of supply.

- On 2 July 2001 the Polish Oil and Gas Company (PGNiG) signed a contract with a Danish company DONG for a supply of 2 billion m^3 of gas annually for the period of eight years, starting in 2003;
- On 3 September 2001 a Polish-Norwegian contract was signed for the delivery of natural gas. The contract provides the delivery of 74 billion m^3 of natural gas in the years 2008-2024.

Electricity Directive

Structure of the sector

The structure of electricity sector in Poland allows introduction of the efficient regulation. At the end of the day there are no vertically integrated undertakings on the market. Instead there are three clearly separated sub-sectors: generation, transmission, and distribution. This is a very good basis for fair competition. As anti-trust authorities are against vertical integration, looking for profit market operators are subject to horizontal integration. Parallel process is the privatisation of

26 Draft Directive amending Directives 96/92/EC and 98/30/EC concerning common rules for the internal market in electricity and natural gas, COM (2001)125, Brussels, 13.3.2001.

27 Green Paper - Towards a European strategy for the security of energy supply, COM(2000) 769, Brussels, 29 November 2000.

stated-owned companies, which also changes structure of the sector.

Existing structure not only lays down a very good basis for introducing pro-market regulations, but also it is a great possibility to follow the Electricity Directive requirements. Unbundling is easier, TSO independence guarantied and competition easy to monitor.

Electricity market regulation

The Energy Law provides the necessary legal conditions for economic activity in electricity generation, transmission, distribution and trade. It introduces TPA and sets the general framework for gradual market opening. It is considered as a very good regulation for electricity market. It is also important, that it was prepared at the same time as the Electricity Directive. That is why both regulations are similar. Some gaps still exist, but these are relatively easy to close. The most difficult task for the future will be to solve some political problems like speed of the market opening.

All the existing gaps will be closed by the above-mentioned Energy Law amendment, which is already in the pipeline. What is important, Polish experts want to transpose some of the regulations envisaged in the Draft Directive.

Apart from the Energy Law, three secondary acts are very important for the market regulation.

- Regulation on tariff setting mechanism sets the conditions of tariff setting by market operators. It defines the TPA as the regulated regime, as the tariffs must be approved prior their entry into force by the regulator.
- Regulation on connection to the transmission network sets the conditions for connection to the transmission grid.
- Regulation on the TPA regime sets the timetable for market opening.

Market regulator

The Energy Regulatory Authority was established in 1997, on the basis of the Energy Law. ERA is the energy market regulator. As it was mentioned before the office is responsible i.e. for electricity market regulation. The competencies on the electricity market are similar to these on the gas market.

- granting authorisations for electricity generation, electricity transmission and distribution, electricity trade;
- regulation of electricity prices;
- control of supplied electricity quality;
- settling disputes concerning connection to the network;
- co-operation with anti-monopoly authorities to promote competition in the electricity sector;
- assembling the information about electricity market and investments in the sector.

As the competencies of the regulator are similar to the gas market the gaps are similar as well. ERA President can not grant an authorisation either for transmission or for distribution. It could only be granted for “transmission and distribution”. The second gap is lack of competence to assemble information about investments in the electricity market in order to transmit it to the European Commission.

Tariffs

Tariff setting is regulated by the Energy Law and the Regulation on tariffs. Despite pro-market structure cross-subsidisation exists in the electricity sector. According to the government declarations Poland will remove price distortions in 2004.

Taking into account the advanced process of implementing the competitive market mechanisms, the President of ERA acknowledged electricity market as competitive. Therefore, since 1 July 2001 enterprises having authorisations for electricity generation or trade have been exempted from the duty to submit tariffs for approval.

Still to be approved are the tariffs set by:

- enterprises generating electricity and heat – as regards energy that has to be purchased in accordance with the Regulation of the Minister of the Economy of 15 December 2000 on obligatory purchase of electricity generated from renewable sources and electricity from co-generation and the scope of the obligation;
- transmission system operator;
- companies with authorisations for electricity transmission and distribution.

The above-mentioned decision makes it difficult to define type of the TPA regime on electricity market. But the most important thing is that transmission system operator and distributors have to have its tariffs approved before they enter into force (Regulated TPA). That solution is fully compliant with the Draft Directive.

Opening of the electricity market

The opening of the Polish electricity market is based on the Energy Law and the Regulation on the time schedule of obtaining by particular customers the access to transmission services. The Table 2 compares Polish timetable with these envisaged by the Electricity Directive.

Table 2. Opening of the electricity markets in Poland and EU countries

Type of eligible Customers	EU countries	Poland
Customers buying more than 40 GWh	19 February 1999	1 January 2000
Customers buying more than 20 GWh	19 February 2000	-
Customers buying more than 10 GWh	-	1 January 2002
Customers buying more than 9 GWh	19 February 2003	-
Customers buying more than 1 GWh	-	1 January 2004
Customers buying less than 1 GWh	2005?	5 December 2005

It is hard to compare two above described timetables as they define different customers groups. But generally speaking the market opening speed is similar. What is important here, Poland has defined date of 100 % market opening as for December 2005. Similar date could be found in the Draft Directive.

The gap in this field is again Polish TPA regime. The free choice of suppliers exists, but it is restricted only for electricity generated in Poland. This problem still exists, but it was already agreed that any barriers for foreign players will be removed on the day of accession Poland to the EU.

Unbundling

The same gap exists here as in case of natural gas market. The Energy Law provides only for keeping separate accounts and there is no obligation for electricity undertakings to prepare separate balance sheet and a profit and loss account for each of the activities. The gap will be closed by the Energy Law amendment.

The important advantage for unbundling is the existing structure of the sector. It allows keeping transparency especially when we consider access to the transmission or distribution system.

Summary

It has to be said that the implementation process of the Gas and Electricity Directives is going well. The complex amendment of the Energy Law is already in the pipeline and its regulations will facilitate closing the gaps mentioned in this paper.

Electricity market structure is functioning well and it should be a good example for the gas sector to follow.

If all the changes envisaged by the draft law or governmental programs will be introduced, there is a real opportunity for Poland to become the important player on the internal energy market.

Nevertheless, there are still some major problems, which are really difficult to resolve. Restructuring of the gas market is under the question mark. This sector was always influenced by the politics as the strategic for the Polish economy. All the changes in the structure and especially in the ownership are really difficult to introduce.

For the electricity sector stranded costs still remain a problem. Despite several drafted solutions the issue remains unsolved. The scale and impact on the competition is great as the amount of electricity traded under long-term contracts reach 70%.

Bearing in mind the problems mentioned above, there is still a long way to go towards establishing a competitive Polish energy market. Despite actions undertaken, still a lot of work is to be done. Good pieces of regulation are in the pipeline, but some issues can not be solved by the legislation. The good co-operation between legislators and market operators is needed. New investment, especially in the interconnection capacity is also a must.

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Regulation of the Minister of Economy on the detailed conditions of tariff setting in gaseous fuels trade (OJ No 1 of 15.01.2001).

Regulation of the Minister of Economy on the time schedule of obtaining by particular groups of buyers of the rights to transmission services (OJ No.107 of 20.08.1998).

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Development of the Romanian electricity market

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Introduction

The total available capacity of the Romanian generation system at the end of 1999 was 15,079 MW, of which 40% were in hydropower plants. Due to the decrease of the electricity consumption, the electric power system developed an overcapacity. It is clear the transition to a market economy had a strong impact on the electricity sector, as consumption decreased between 1989 and 1999 about 5.6% per year from 71.4 TWh to 39.9 TWh.

Taking into consideration the evolution of Romanian energy sector in the transition period, it is important to achieve for the Romanian energy market a proper fuel policy, an economic evolution of domestic primary energy resources, an adequate energy pricing policy and a proper restructuring of the economy.

Evolution of the Romanian electricity market

Romania is engaged in the process of accession to the EU and is making efforts to align to the provisions of the EU Directive 96/92/EC regarding common rules for the internal electricity market. Consequently, the following conditions have been considered as priorities for the creation of the electricity market in Romania:

- division of the production, transport/dispatch and distribution/supply activities:
- access to the transportation and distribution networks correlated with the appearance of eligible consumers; in this way it is expected to encourage the introduction of the competition to the distribution/supply side and the improvement of the production offer.

In this direction, Romania has taken the following steps :

- ratification of the both Energy Charter Treaty and Energy Charter Protocol (year 1997);
- creation of the National Authority for Regulation in the field of Energy – ANRE (year 1998);
- approval by the Parliament of the “Electricity and Heat Law” (year 1998);
- approval of the “National Strategy for privatization for year 1999” with the main objective of the reform policy to end the restructuring of the energy sector by creation of the regulation and institutional framework; continuation of the national energy companies restructuring by separation and establishment of independent commercial companies suitable to be privatized; creation of the Commercial Operator, and the mechanisms and infrastructure for Electricity Stock; increase of the interconnection degree with the UCTE networks;
- the establishment for year 2000 of an initial opening of the electricity market to the competition (in the first stage to 10% of the final electricity consumption about 4 TWh).

The Romanian wholesale market of electricity was created in the year 2000. It isdevelops based on the principles deriving from the primary Romanian legislation and from the necessity of the alignment to the provisions of Directive 96/92/EC. Important aspects include the following: :

- the market operates through commercial arrangements between the participants concerning the electricity and the associated services, defined in the Commercial Code of the wholesale electricity market;
- the regulatory framework assures an non-discriminatory and transparent treatment for all participants in to the market;
- at the level of the producers and suppliers, the market becomes gradually competitive; it is imposed a gradual transition for an efficient control of the risks, in view the initial structure of the sector (monopoly, vertical integrated); for transportation and distribution activities, the market is fully regulated;
- the access to the market is performed by the licenses;
- any participant in the market (license holder, eligible consumer) is justified to have a regulated access to the transportation and distribution networks;
- the market of the regulated contracts regarding prices and quantities, operates in parallel with the competitiveness market performed by bilateral negotiates contracts and the spot sales and purchasing; at the beginning the spot market appears to compensate the contracts differences;
- the deliveries on the wholesale market are based on the producers’ offers and are established through a specific mechanism defined in the “Regulation for electric system programming and dispatching”;
- the eligible consumers can choose their electricity suppliers that performs contracts, bilateral and negotiated (quantities and prices);
- connection to the electricity transportation and distribution networks is considered an obliged public service, regulated;
- any new participant to the market is treated in the same way as the existing participants;
- the market access and applied prices are non-discriminatory for the electricity generation technologies and energy resources used.

The market manager is Commercial Operator, which ensures the operation of the market mechanisms according to the “Commercial Code of the electricity wholesale market”. In the short term, the main participants to the market will be producers, buyers (distributors, suppliers, producers, eligible consumers), transportation operator and system operator. For mid term, by reduction of the risks and fluidity of the financial operations, the intermediary agencies for supplying (energy brokers), representatives of the producers or consumers will be admitted.

From the point of view of the commercial market relations, the Romanian electricity producers can be grouped such as:

- producers proceeded from National Electricity Company: Termoelectrica and Hidroelectrica;
- independent power producers (including National Company “Nuclearelectrica”);
- auto-producers.

The producers - owners of the capacity generation portfolio - sell electricity to suppliers and eligible consumers.. The commercial arrangements are regulated by the following: portfolio framework contracts for the sale/purchase of the electricity, framework contracts for transportation and system services, framework contracts for the supply of electricity to eligible consumers, and framework contracts for electricity acquisition from independent power producers or auto-producers. Portfolio framework contracts for electricity sale/purchase are based on the calculated merit order. By increasing of the opening degree of the market, the share of the guaranteed quantities will progressively decrease. For the privatization of the distribution/supply and/or production companies, the portfolio contracts represent a transparent and credible base for negotiation.

At present, the average supply price of Commercial Company “Electrica” results as an weighted average value of the producers prices and supplying quantities. This principle will be applied and after the division of the Commercial Company “Electrica” into many companies. The number and the structure of the new distribution/supply companies will be optimized considering the principle of the performing of the some specific costs. Thus, each distribution/supplying company will purchase the required quantities of electricity from the same “basket of producers”, at the same price established by the initial portfolio framework contract (Fig. 1). Efficiency of the activity will be reflected in their own efforts to reduce the costs.

One IPP has, on the mid term, the following possibilities to trade the electricity:

- contract type PPA (purchase power agreement) for 12 – 15 years with one of the producer;
- contract type PPA with suppliers;
- bilateral contracts with eligible consumers;
- transaction on the spot market.

The management of the electric system is ensuring on the economic loading order. With priority in the merit order, the generation units with constraints are placed, such as: the hydroelectric power plants, NPP Cernavoda, the co-generation units at the optimum level imposed by the heat load, burning of a pre-established quantity of coal.

In the medium-term, the commercial companies resulted by separation from National Company “Electrica” will be the electricity distributors and suppliers. The activity of these companies is regulated through portfolio/framework contracts for electricity sale/purchase, the framework contract for distribution service, the technical code of the distribution networks, and the supply framework contracts for captive consumers.

The accreditation of the eligible consumers for creation of the competitive market is an important reform measure of the sector. Criteria and requirements for eligibily refer to the level of annual consumption (100 GWh/year in the first step). For year 2000, the initial opening degree of the electricity market was established to 10%.

In accordance with the economic transition and the success of the privatization process, it is possible to license all industrial consumers with a consumptions higher or equal with 100 GWh/year; that would correspond to a 25% opening of the market. The continuation of the accreditation of industrial consumers with a consumption higher than or equal to 40 GWh/year would determine the increase of the market opening to be about 35%.

The transportation operator performs the public service of transporting electricity at the regulated tariffs. The activity is regulated by the “Technical code of the transportation network”, the “Commercial code of the electricity wholesale market”, the framework contract for service catering, and the commercial operation licence of the electricity transportation capacities. For prevention of the uneconomic development of the electricity system, regional tariffs are expected to be introduced. The regional tariffs will stimulate the operation/construction of the generation capacities in the deficit area. Introduction of the regional tariffs will allow for consideration of the different tariffs for transportation., in order to establish the merit order.

The system operator ensures the operation, coordination of the production, transportation and distribution installations (at 110 kV tension), operative planing, and operative management of the power system. The system operator develops the activity based on the dispatching licence and enters into purchase contracts with the producers for the technological system services. At present, the tariffs for the system service are regulated. The prices and tariffs have an important role in the market liberalization, to stimulate the competition and protection of the consumers’ interests. By improvement of the electricity tariffs system, it was possible to reduce the cross-subsidies from industrial consumers to the residential consumers. This was carried out by adopting new tariffs for industrial consumers and residential consumers. In the future, tariffs are expected to be based on the average costs, on the marginal costs, and on the price-cap.

The alignment of the Romanian energy regime to EU legislation should improve the consideration within the tariffs of the external costs (for instance, the environmental impact cost). The introduction of the same incentives for development of the energy efficiency projects or projects using renewable energy sources, for instance, through taxes, will reflect the policy of environmental protection.

Conclusions

Romania has made significant progress in deregulation of its energy sector and in establishing a competitive electricity market.

The Ministry of Industry and Resources, as owner of almost all entities in the sector, has achieved a institutional reform. New relations have been established through regulations issued by ANRE among the new producers, suppliers, transport and distribution companies.

With a 15% competitive market, a functional day-ahead spot market, and 8% of electricity directly negotiated between suppliers and eligible consumers, the Romanian reform in the electricity sector can thus far be considered a success.

Session 3: The Implementation of the Gas Directive

Rapporteur's Summary by Eugene D. Cross, ECN Policy Studies, The Netherlands

Session Three was comprised of six presentations and related discussions on the development of the European gas market, the implementation of the Gas Directive, and the Commission's proposals to amend the Gas Directives.[28] This session was the gas counterpart to the previous day's session on electricity. The underlying effort was to gain a more definitive assessment of the consequences of the liberalisation in the gas sector and to identify topics for further inquiry.

Mr. Rousseaux reviewed the current state of implementation of the Gas Directive, the proposed amendments, the impact of the market opening since August 2000, and the Madrid Forum. He described the difficulties and barriers related to grid access, including the market structure, and he pointed out the reasons that gas liberalisation in Europe is more difficult than electricity liberalisation.

Following Mr. Rousseax's presentation, a lively debate centered on the Commission's recent proposals regarding the duties of regulatory authorities. Mr. Cross inquired whether the Commission, in formulating its draft proposal, had considered requiring that such regulatory authorities should have a primary duty to promote competition, such as is the case for the British regulator, Ofgem. Mr. Rousseaux indicated that such a proposal by the European Commission was unlikely and that even when such a duty would be imposed on independent regulators such as Ofgem, national governments still need not necessarily follow their lead. In other words, regulators can be ignored. Other commentators responded that cartels in the sector were progressively strengthening, and that competition authorities were "watching but not acting". It was argued that whether to promote competition in the internal energy market is largely a "political" choice to be made by the EU institutions and the Member States, and that the Commission could act more forcefully and pro-actively in this regard.

Peter Claus of Eurogas, representing the gas industry's view, acknowledged that the EU has a role to play in ensuring energy co-operation with non-EU supply areas. In particular, the European Commission's Competition Directorate has to put pressure on non-EU suppliers.

However, Eurogas does not see a need for the proposed directive to amend the Gas Directive. "There is no need to develop EU legislation further, since there is a Gas Directive already as well as new national legislation in place or being developed." His main conclusions are that gas markets and liberalisation efforts must take place in a more volatile and uncertain environment and that Europe needs "large and competent companies to compete with outsiders or raiders".

The paper of Geert Greving of Gasunie, set forth below, provides further depth to the issue of security of supply, focusing on cost and price data for both Russian end-users and for the Hungarian natural gas sector. He also refers to the need for introducing more "slack" capacity into the European natural gas grid through legislation and suggests that the TSO should charge for this overcapacity on the basis of a regulated price; i.e., that the TSO should agree with the regulator how to account for slack capacity in an open transmission system, which is perhaps owned by several operators, but in any case used by many shippers. He also advocates the idea of "installing an annual watchdog function for ongoing investments in energy network facilities." The European Commission has recommended in its draft proposal to amend the Gas Directive (COM(2001) 125) that Member States shall designate a body to monitor security of supply issues, and in particular the supply/demand balance in its national market and the level of future demand and available supplies (Article 4a). It is proposed that this body should issue an annual report on the security situation and any related measures.[29]

In the subsequent discussion, Mr. Rossetti of DG-Research inquired why natural gas prices in the retail/sales market are not decreasing for consumers. Mr. Claus referred in passing to the link between natural gas prices and oil prices, but his main argument is that market liberalisation within the EU can have an impact only on costs from the EU-border only. In other words, "liberalisation can only affect the post-import costs (for imported gas)", and that the post-import cost component of the final gas price is only 15-20% maximum[30]. His assumption, of course, is that the import price cannot affected by EU liberalisation even if natural gas prices within the EU are substantially decreased. Asked whether there is a tension between the introduction of competition and security of supply, Mr. Claus stated that Eurogas has no official position on it but would agree with the oil industry's view. Eurogas "does not want to give government influence over commercial decisions";

28 Proposal for a Directive of the European Parliament and the Council amending Directives 96/92/EC and 98/30/EC concerning common rules for the internal market in electricity and natural gas.

29 This requirement for a monitoring body has been dropped from the later proposals for amending the Electricity Directive, in favour of a requirement that Member States simply "shall ensure the monitoring of security of supply issues". Similar changes may be made to the proposals to amend the Gas Directive.

30 In contrast, the cost data for Hungary supplied by Geert Greving in his paper entitled "European energy security: an urgent energy policy topic" indicates that post-import costs in Hungary (transmission, distribution and storage) are equal to about one-half of the typical commodity price at the border, making the post-import costs amount to about 33% of the final end-user price.

instead, the gas sector companies should do it themselves. Governments should perhaps give targets following consultation with the gas sector, but there should be "no obligations", rather just targets for companies.

Dominique Finon reported on his recent research on the European gas sector, seeking to identify the requirements for establishing reasonable short-term competition among an oligopolistic club of incumbents. He noted the greater elements of resilience to liberalisation for the gas sector compared to the electricity sector. He has ranked the general accessibility to national gas markets based on comparisons of conditions of network access, the level of transparency of network access, and the technical and institutional accessibility of national gas markets. He concludes that markets are not as competitive as they look, and that there is still one European bulk market and 15 national markets in the EU.

Admittedly, we can have a legislated process for the gas sector as with electricity, but one can query whether we really need to liberalise the sector. There is an ideological concept at work in the EU that we seek to integrate the market -- to establish the internal market -- through liberalisation. This move is unavoidable, and we need to apply the rules to the accession countries as well. However, the real limitation to the development of competition is the existing long-term contracts. Rapid progress would imply cancellation or radical revision of these contracts, but flexibility on volume and price limits the possibilities for this.

Analyses of the natural gas markets in the Czech Republic and Romania were offered by Mr. Stepan (ENA Ltd.- Czech Republic) and Mr. Furlan (ENI – Italy) respectively. In the Czech Republic, Transgas is the sole owner and operator of the transmission networks (including dispatching and transit) and the storage facilities. In 1999, imports covered 98% of total supply. Transgas supplies to distribution companies and has five big industrial clients that are supplied directly. There was a 36% price increase in 2001 in the gas price, but there is still a large gap with prices in the EU Member States. The price for gas to the residential market is 30% higher than coal, so further increases in the residential gas price would allegedly lead to switching to coal. Because the import price of gas was high in 2000 and 2001, the competitiveness of gas against other fuels in the Czech Republic is not very good. The privatisation of Transgas by the National Property Fund is under negotiation, and there are predictions that a bidder will be selected by year-end.

In Romania, the largest gas market in Central Europe, there is a separate gas regulatory agency, the National Agency of Mineral Resources (NAMR), subordinated to the Ministry. It prepares bidding rounds for new exploration, negotiates concession contracts, regulates the gas sector, and proposes prices and the transmission tariff to the Ministry of Finance. ROMGAZ has been restructured into new companies responsible for exploration and production, transmission, storage, and two distribution companies. In the Commission's regular Progress Report for 2000 on Romania's progress towards accession, it noted concerns about the compatibility of Romanian rules to establish a transparent framework for the gas sector with the Gas Directive's rules on unbundling of accounts in vertically- integrated companies. It also noted the problem of unpaid energy bills in Romania, a crucial problem that is growing and which threatens the whole energy sector of the country. Mr. Furlan noted that any theoretical advice on Romanian reform must be tempered by an appreciation of the social situation. Along the same lines, he stated that the local reality in Romania does not support an acceleration of the liberalisation as envisaged in the proposals to amend the Gas Directive.

European energy security: an urgent energy policy topic

Geert Greving, N.V. Nederlandse Gasunie, Gronignen, Holland.

The Russian/European Energy Dialogue

In the last few months the Putin/Prodi energy dialogue has been underlining the emerging discussions on energy security for Europe. This kind of discussion is also important for the internal European debate on the EC green paper: energy security, which is due for discussion with the European energy partners from outside the region.

Russian energy policy

For many years Russian energy policy has been hidden from outsiders or only partly revealed to Europe and discussed piecemeal. During the Russian-European Energy Partnership the Russian energy policy for all its energy sources has been revealed and explained and, moreover, openly discussed by expert teams from East and West. This unique situation underscores the serious desire on the part of both sides to establish a real partnership in the field of primary energy.

Past efforts by the IEA and several Russian energy experts attempted to piece together the Russian Government's energy policy, but only during the Russian-European expert meetings has the complete picture emerged and, more importantly, been confirmed.

Russian energy priorities vis-à-vis the West.

Russian priorities as far as the West is concerned are easy to explain, based on natural gas and oil – and the nuclear sector. The main Russian goals are:

- to earn hard currency from exports
- to become a reliable exporter to Europe (high, stable prices)
- to become a priority exporter with enlarged capabilities.

The main driver for energy exports from the Russian Federation is the need for hard currency. The public sector budget will continue to need the hard currency income generated by exports to Europe in order to remain in balance and also to keep on course in the present transition period. There are hardly any other options open to the Government and the Russian energy sector has a key role to play in these efforts.

It is reliable exports to Europe that will generate the most revenues. The less reliable the exports, the less hard currency will be earned by the Russians. Stability and continuity of energy export flows to Europe are therefore the key as far as the Russians are concerned.

Given the decline of indigenous energy resources in Europe itself, more and more inward energy flows will have to be contracted in order to enable Europe's manufacturing base to keep pace with growing demand. In this setting, the main outside supplies for Europe will come from Russian energy sources.

Moreover, the Russian energy sources have the potential capacity required and, more importantly, are already connected to the European energy markets where the demand exists. Only marginal investments are needed to enlarge the present energy transmission capacities to the European energy markets. Even these marginal investments, however, are of quite a magnitude. We shall discuss this issue in more detail later.

Russian potential greatest with respect to natural gas

The potential as regards the various energy flows to Europe provided by Russian companies is the greatest for the natural gas sector.

The present scope for the export of more nuclear energy to Europe is limited by current European Energy Policy, with its focus on reducing nuclear capacity in future.

Oil exports to Europe are more or less sandwiched by the present export capacities on the one hand and by the quality of the product available for export on the other. Export quality has to be improved before there can be any market enlargement towards Europe, either by installing new production units or by building more dedicated pipelines, carrying different grades of oil to Europe.

The conclusion, therefore, at least for the next ten years is that priority will be given the Russian natural gas sector, in view of its potential compared with the other possible energy flows.

The natural gas sector is of mutual interest. On the Russian side the potential for future exports is "large", while from the European point of view, energy policy is focusing on the fuel of choice: natural gas. This has everything to do with the European drive to achieve the future agreed emission levels under the Kyoto protocol, with subsidies in Europe generally aimed at higher penetration of natural gas in Europe's total primary energy mix. In most of the countries of Europe, the fuel mix is such as to support the penetration of natural gas more than before.

Energy security, inherent to natural gas

Energy security, in comparison with oil at least, is an inherent quality as far as natural gas is concerned. Oil is a commodity that is typically sold in energy trading markets and, moreover, it is shipped in pipelines and mammoth tankers from global producer locations to end-users, wherever they are.

In Europe, only around 5% of the total volume of natural gas consumed is shipped by mammoth tankers. In Europe, therefore, the LNG trade and shipments are negligible. The main transport system in Europe is still and will continue to be pipelines. They may be quite expensive to build, but once built they are pretty well there for the duration (technical life of 50 years). This unique investment background allows certain assumptions to be made where project investments and partnerships involving investors and/or pipeline operators are concerned.

Natural gas security of supply

The issue of security of supply in relation to natural gas is not only a matter of volume but is also very much to do with capacity. Capacity is a key issue in the natural gas sector throughout Europe, connected as it is to seasonal fluctuations and the high load factor necessary for the transmission of natural gas over long distances. The volume currently shipped over long distances is 40% of the total volume consumed in Europe. In the near future this figure is set to rise strongly to around 70% by 2010. Depending on domestic European reserves (mainly depending on the export capabilities of the UK, Norway and Holland), this figure could turn out a little bit higher or lower.

With an increase in long-distance natural gas supplies to European markets, more and more load factor conversion will be needed. It goes without saying that load factor conversion, i.e. temporary storage of natural gas, is extremely expensive in comparison with the storage of oil.

Securing a downstream natural gas market in Europe means balancing pipeline capacity bringing long-distance gas to the consumer and natural gas storage in order to match the end-user load-factor to the high load-factor associated with long-distance supply (average end-user load factor of 0.6 compared with a load factor of 0.95 for long-distance transmission).

If costs and commodity prices are considered in order to gain a feel for the situation and cost relationships, the Hungarian natural gas sector serves as a good example for illustrating the overall picture.

The commodity price at the border in Europe is typically around US\$90-100/1000m^3, depending on oil and/or coal price indexes. The costs for high-pressure transmission in Hungary are around US\$10-11/1000m^3 as an national average, while storage costs – or should we say load factor conversion costs – are in the order of US\$20/1000m^3. Last but not least, distribution costs are in the order of US\$26-28/1000m^3. It is clear, therefore, that load factor costs represent an appreciable part of the value chain from gas well to end-user appliance. The total end-user price in Hungary will be around US\$150-160/1000m^3.

The Californian experience and natural gas

The Californian case, in terms of volume, capacity, legislation and other related issues, has been compared to the situation in Northern Europe. An internal study carried out by the University of Groningen has shown that the starting conditions in this part of Europe are the same as in California. More or less the same is true from a liberalisation point of view, with a comparable open and deregulated consumer market to begin with.

As in Europe, the Californian natural gas sector started from out from an oversupply position in terms of both volume and capacity. Now that the overcapacity in California is a thing of the past, capacity shortages are driving up end-user prices steeply.

A key factor in this game has been the introduction of so-called ‘slack’ capacity into the natural gas grid. By scheduling both long and short-term overcapacity, the idea is that transmission prices should be kept within a certain bandwidth. The present lack of slack capacity is strongly pushing up the transmission prices and, with them, the energy bill of end-consumers.

How to deal with slack capacity

Introducing slack capacity is easy to incorporate in legislation, but actually using and operating slack capacity is quite another matter. In a full-scale network, operational capacity has to be calculated and controlled, not only for the next 24 hours, or next month, but for the next few months and in the long term, too. If all required and/or contracted transmission capacity is being carried, slack capacity has to be scheduled into the system and continually monitored and adjusted. Given the fact that slack capacity is by definition never used and/or paid for by a shipper, the transmission system operator will have to agree with the regulator how such overcapacity is to be paid for. This is not only a matter of what tariffs to apply for slack capacity but, more particularly, how to account for the slack capacity in an open transmission system, maybe owned by several operators and in any case used by many shippers. Another issue is of course who will be responsible for slack capacity, trying to avoid transmission capacity shortages and, at the same time, avoiding sky-high end-user prices, as is the case today in Canada and California.

The short-term versus long-term debate

These issues have already been hotly debated as regards European energy policy. Newcomers are keen to have a full short-term market, while the established players are strongly in favour of more long-term commitments, avoiding a European spot market.

If we again examine the situation in California, we find ourselves dealing with a short-term market for natural gas overall. The market is setting prices and recently they have been extremely high for end-users. It seems that it is not energy policy that is dictating the final bill for end-users, but the current spot market prices.

The Californian case is even more unique if the natural gas market here is compared with the one in Canada. In Calgary, end-user natural gas prices are much higher than in Vancouver, even ignoring the fact that the region of Calgary is a reserve-based region. Vancouver has to supply its consumers over a long distance from Canadian fields.

The difference in market mechanism is the overall short-term energy business in Calgary, while Vancouver is almost entirely supplied by long-term commitments. Here it seems that a balancing approach is far better than an approach based solely on spot market conditions. It is expected that Europe will be based mainly on long-term commitments and supply contracts, with short-term volumes reaching between 5% and 10% of the total volume. The long-term contracts will smooth out short-term volatility and the effects of possible market dealing by paper traders.

Public service obligations

In Europe, and especially Central Europe and Eastern Europe, there are public service obligations towards residential consumers.

Residential consumers, who will always have a low load factor, are paying a higher price than industrial consumers with a high or at least higher load factor. The less natural gas that has to be stored the lower the costs that are associated with the delivery of energy to the end-consumers. At least, this is the case in Western Europe.

The situation in Central Europe is more complicated. This region traditionally charged residential consumers a lower price compared with the industrial users. This involved cross-subsidisation and, during the last couple of years, most of the Central European counties have been adjusting their fuel mix to something more like that in Western Europe.

In Russia the situation is different again and more complicated, given the high priority accorded to public service in Russian society. Not only is there cross-subsidisation in Russia but commonly also extensive total non-payment for energy in the residential market (80% of the market segment), which is a serious problem.

Gazprom as Russian public service provider

Against this background, it is clear that OAO Gazprom is seen by the Russian Government as a public service provider, including the non-payment behaviour of its end-consumers. Whereas the end-user price in Hungary is in the range US$150-160/1000m^3, the end-user price for Russian residential customers is set at a level of US$11/1000m^3. This price is due to be raised in 2005, to a scheduled level of around US$20/1000m^3, an increase of 100%.

The cross-subsidy needed to keep OAO Gazprom afloat is supplied by the exclusive natural gas exports to the European hard currency markets.

It is clear that the present Russian transit economy needs time to adjust to what is common practice in the more Western economies. For this reason, it may be expected that the exclusive rights enjoyed by OAO Gazprom with respect to its export markets will continue to apply for some time to come. Officially, third-party access for other domestic natural gas producers to the Unified Soviet Fuel system operated by OAO Gazprom has already been introduced and is due to be extended in terms of volume. However, the gateway capacity to the high-priced European export markets will continue to be restricted to OAO Gazprom.

Given the timetable for price rises for natural gas in Russia itself, it is to be expected that there will be a timeframe of more than 10 years before the present barriers to changes in the internal fuel mix in Russia can be overcome.

Liberalisation drive in Europe on investments

The liberalisation drive presently taking place in all EC member states is raising a lot of questions for both new and established players in the natural gas industry where new investments in network facilities and/or systems are concerned.

Under the energy partnership between Russia and Europe, the return on investments in new network facilities was set at a level of 6%. This figure is out of line with the current level of return expected by energy industry players. These days any feasibility study will start from a level of 15% (return on investment). If 6% is applicable we have to look to long-term investors like pension funds for this kind of deep investment.

Apart from such considerations, it is also apparent that the Commission in Brussels wants to see international tenders for any new interconnection in Europe. Precisely what these tenders will involve and what their terms and conditions will be has not yet been decided or clarified.

If the existing players in the market put things on hold for a while, the present overcapacity, whether in relation to volume or transmission capacity, will soon disappear, while on the other hand the natural gas market will steadily grow under the present energy policy of the European Community, which focuses strongly on the fuel of choice: natural gas.

Investment in interconnections with Russia

The above state of affairs will hit trans-European investments tying in the energy resources of Russia even more. Already it is extremely difficult for major energy companies, like Shell, Exxon, Total/Elf, BP, etc to establish project finance in Russia. The developments surrounding Shtokman will need extremely large and deep investment, to give but one example. In the Shtokman case we are talking about a level of investment of more than US$20 billion. This is a project on which investments will have to be made up front, with the owners having to wait for a period of at least 5 years before they see so much as a penny in return. Every one of these projects will involve an international player and a Russian partner, with the Russian partner not having access to unsecured credit lines.

Quite apart from the huge capital cost involved we have to recoup the investment in the long term, which is another difficult issue associated with the present liberalisation drive of the European Community.

The long-term commitment

In the final report on the energy partnership between Russia and Europe, the issue of the long-term commitment and, in particular, the vital long-term contracts between Russian supplier and European end-consumer have been addressed, but they have certainly not been solved.

The report states (see annex) that this issue will be handled swiftly, but so far no clear solution, and no solution encouraging any investor to go ahead with any investment either in the Russian region or in the region between Europe and Russia, has been put forward.

Given this situation, any pipeline or vital interconnection capacity between supply area and European energy market can be expected to be put on hold until further notice.

The outlook

The energy partnership between Russia and Europe brought the right discussion, started by the INOGATE drive by the European Community, back on track, namely to focus on the largest European volume supplier: Russia. A stable and extended relationship between Russia and Europe will be mutually beneficial. Stability has always been the cornerstone for a reliable and, moreover, profitable European Energy sector.

Enormous energy supplies, especially flows of oil and natural gas into Europe, will be crucial to sustain the economy of Western Europe, but this will necessitate attracting investment in the existing supply system and, moreover, new investment in new infrastructure and upstream developments, as well as putting the new infrastructure into operation.

The present liberalisation drive is killing the prerequisite for investment.

The position of, for example, the European Investment Bank vis-à-vis upstream Russian investments is crucial in order to produce the right conditions for attracting new investors to this kind of investment. The range of instruments available to the EBRD will be too limited in the face of the huge investments needed.

An investment watchdog

It was for this reason that the idea of installing an annual watchdog function for the ongoing investments in energy network facilities was launched.

Certain energy policymakers are suggesting a situation in which investors will be attracted anyway, regardless of the level of return on investments. It has got to be one thing or the other.

The existing players are stressing the present extremely weak investment climate for investing in major networks in Europe and are not even looking at upstream options in Russia. Whatever the case, the installation of an annual ‘watchdog’ would be in everyone's favour and would produce evidence as to who is right and who is wrong.

One thing is clear, any predictions about the future are bound to turn out wrong, but at least a watchdog or annual meeting between the various parties involved could produce information about the investment climate and could also produce initiatives for improvement.

Session 4: Green and clean electricity

Rapporteur's Summary by Miroslav Maly, SRC International CS, the Czech Republic

Session Four was comprised of three presentations and related discussions on Green Certificates in the EU context, obstacles and opportunities for distributed power generation, and impact of Swiss Electricity Law on competitiveness of hydropower.

This session dealt with the situation of green and clean electricity generation in the framework of the electricity and gas market opening in EU member and non-member countries.

Mrs. Maroeska Boots, ECN, presented the basic principals of the EU policy in promotion of the renewable electricity as stated in the EU RES-E Directive. She reviewed the national RES-E targets and the current state of their meeting by EU country. She explains basic principles of the trade in Green Certificates (TGC) and national TGC systems by individual EU country. She further discussed the issues in international trade and the Dutch criteria for TGC import. In more details she presented the results of REBUS model calculations on costs and potentials for RES-E in the EU as a whole and by individual EU Member State. She concluded on the expected green certificate price and the impact of various factors on its level. She also discussed the interaction of GC and CO_2 reduction policy.

Mr. Aviel Verbruggen, UA-UFSIA-STEM, opened his presentation with a brief review of basic individual technologies used for distributed generation. The technologies for supplying distributed power are becoming more efficient, reliable and flexible. Fuel cells and photovoltaics are promising futures. The actual development of distributed projects however faces several barriers. He discussed informational barriers and barriers related to the distributed character of renewable and co-generation plants. After a general discussion on the control of renewable power and grid connection, most focus was on the terms of trade between distributed generators and the grid. This is a complex issue because of the difference in value of a kWh depending on time, place, quality, reliability and liability of supply. Especially the latter factor is subject to evaluation, opinion and policy. Even when today special arrangements improve the terms of trade for distributed generators, we argue to keep the basic economic terms in scope to avoid moral hazard with subsidy money and to give priority to robust distributed solutions above subsidy addicted ones.

Mrs. Silvia Banfi, CEPE, presented the paper on the impact of Swiss electricity law on competitiveness of hydropower. Although Switzerland is not a EU member country, the Swiss Parliament adopted the new Swiss Electricity Market Law (EML) in December 1999. The EML laid the foundations for reforming the Swiss electricity industry by moving from regulation to deregulation. Mrs. Banfi briefly described the Swiss electricity industry and details of the reform plans set out in the law. She also analysed the impact of EML on the hydropower firms and an discussed the competitiveness of the hydropower sector in the deregulated market..

The Session four showed that green and clean electricity has been penetrating the European market both in EU Member and non-member states in last years. Nevertheless there are still many barriers to its wider penetration in the future. Thus further promotion policy is needed in EU for faster penetration of RES-E. Some possibilities were presented by speakers during their presentations. Following the discussion among the participants it was agreed that this issue is very important and thus it was agreed to devote the ENER Forum 3 especially to this topic. The title of the ENER Forum 3 has been agreed as: *Successfully Promoting Renewable Energy Sources in Europe*.

Barriers to distributed power generation

Aviel Verbruggen, UA-UFSIA-STEM, Antwerp, Belgium

Keywords. Distributed power, grid connection, barriers, co-generation

Abstract. The technologies for supplying distributed power are becoming more efficient, reliable and flexible. Fuel cells and photo-voltaics are promising futures. The actual development of distributed projects however faces several barriers. We discuss informational barriers and barriers related to the distributed character of renewable and co-generation plants. After a general discussion on the control of renewable power and grid connection, most focus is on the terms of trade between distributed generators and the grid. This is a complex issue because of the difference in value of a kWh depending on time, place, quality, reliability and liability of supply. Especially the latter factor is subject to evaluation, opinion and policy. Even when today special arrangements improve the terms of trade for distributed generators, we argue to keep the basic economic terms in scope to avoid moral hazard with subsidy money and to give priority to robust distributed solutions above subsidy addicted ones.

Distributed power

Many of the power generation technologies that excel in climate change mitigation are of a distributed nature (IPCC 2001, WG III, p.180). On the one hand, there are the renewable power sources such as wind power, small-scale hydro, photo-voltaic conversion. On the other hand there is fossil fuel driven co-generation or Combined Heat & Power (CHP).

Economies of scale in investment and operation are driving the unit size of wind turbines above the MW level and are limiting the downscaling of micro-hydro sites to a level comparable with domestic appliances. The final effect of these economies of scale forces makes the investment in such a particular plant mostly not accessible for single households or for other energy end-users that do not foster a special interest in renewable power generation. Incumbent utilities or dedicated independent power producers are leading in contracting and operating wind and (also “small-scale”) hydro plants. The design and the operation of these plants are supply driven, and not matched to the needs of particular end-users.

Photo-voltaics are different, given their modular character and because of the need for supporting structures that buildings offer at no or very small additional costs. End-users are the natural target market for photo-voltaics.

The applied co-generation technologies and the scales of application vary widely from 100MW’s steam turbines to a few tens of kW’s engines. Popular today are especially the gas turbines available in sizes from a few hundreds of kW’s to over 100 MW. In addition micro gas turbines of a few kW’s to tens of kW’s are developed, that will have to compete with fuel cells. Both small-scale technologies are receiving large R&D attention for automotive applications and the advancements there will trickle down to stationary appliances.

Because heat, one of the products of co-generation, is expensive to transport over longer distances, co-generation plants are linked to heat load sites. The natural market of most of the new co-generation technologies lies in retail sales to end-users that buy the device and install it at home, in the office building, in the factory or at any other energy consumption site. To be technically and financially successful, co-generation plants are site specific, designed and operated to meet the needs of the end-users at the given site.In the wide variety of non-utility producers owning and operating distributed plants, it is necessary to distinguish between the ones that do so for selling power to the grid, and the ones that primarily want to meet the own electricity loads with the power they generate on site[31]. Both groups of distributed power producers face a number of common barriers to their growth, but the latter group faces particular barriers. In this lecture we focus on the barriers impeding the development of the latter group, and we will concentrate on co-generators given the diffusion of photo-voltaics is till limited, although growing rapidly.

Informational barriers

Familiarity with distributed technologies and with the latest developments

In recent years, there have been significant technological advances in turbine (wind, hydro, gas and steam), engine technology (developed for the transport sector), and new technologies for fuel cells and photo-voltaics. These now offer competitive prospects for power generation and for combined heat & power generation, based on decentralised systems of all scales from the few-kW sizes to the tens-of-MW sizes (Major, 1995; Rohrer, 1996; IPCC 2001, WG III, chapter 3). Efficiencies, reliability and steering flexibility have gone up, and investment and operation costs have come down, but this information is not spread widely enough. Also about new developments (e.g. fuel cells, micro gas turbines) little documentation is spread.

This barrier is the most stringent in developing countries and in small institutions and companies, especially when the latter have no technical background. They rely mostly on free information offered by agents that are sellers of particular solutions, and vested interests dominate this kind of information channels.

Understanding the economics of on site generation, in particular CHP

On-site generation is end-user driven, but interconnects with the vast and complex world of energy and energy technology supplies and markets. In order to come up with a long living, i.e. financially rewarding, project, the investor must optimise his system within the given and expected environment. So an investor

31 IGOP or Independent Generator of Own Power

must optimise on site choices, e.g. type of technology, scale, prime mover, and also safeguard the robustness of his system when exogenous parameters change.

Distributed generation works in a complex environment, with a variety of unexpected developments. E.g. even co-generation is known as an energy-saving technology, its profitability can be jeopardised by rising fuel prices. Beginning scholars in co-generation are mostly puzzled by the core paradox of co-generation, i.e. “a co-generation unit assigns priority to meeting the heat end-uses, while maximising power output”. Optimisation of co-generation projects requires extensive information about many determinants of profitability. Heat and power end-uses of the application and in particular the simultaneity of the load patterns, costs and tariffs of grid electricity and the terms of exchange of power with the grid, and the evolution of the fuel/energy markets should all be studied (COGEN Europe, 1997a and b). Experts covering this span of know-how earn high salaries in energy companies or engineering-contracting firms, and are rather employed by vested corporations making their availability to small-scale independent projects exceptional.

Uncertainty about main determinants

A power or co-generation plant is a long-term investment in the energy infrastructure of a company. Several key variables may change during the lifetime of the plant and make investment risky. Examples of uncertain variables are fuel prices, fuel availability, regulatory conditions, environmental legislation, terms of trade with the power grid (Hoff, Wenger and Farmer, 1996).

Barriers related to the distributed character of the technology

Payback gap

Investment money for distributed generation projects is more difficult to get and carries higher interest rates than funds for grid power supply extension and funds for conventional energy supply systems. Mainly when donors, international institutions, banks, etc. are not familiar with the distributed generation technologies, developing countries will not introduce it in their energy supply infrastructure. The flexible mechanisms of the Kyoto protocol (joint implementation and clean development) can prove to be important in overcoming this barrier.

Private investors impose excessive profitability standards on distributed generation projects. This is mainly due to a risk-averse attitude regarding non-core business activities that include the self-generation of electricity.

Because distributed generation has to compete in many places with central supply alternatives the much looser profitability criteria applied on the latter result in an under-development of distributed sources.

Distances to the energy grids (electricity, natural gas) may be large

When there is no link to a power grid, surplus electricity cannot be conveyed to potential customers, and the grid cannot provide supplementary nor back-up power. On the one hand, the additional costs of connecting distant small-scale distributed power sources to the central grid may be excessive, worsening the economics of possible projects. On the other hand, the high connection cost creates opportunities for distributed power (e.g. photo-voltaics in developing countries) when the capacity and willingness to pay for distributed power are available. In the latter case the danger exists of an interconnection realised in the future when central power out competes too expensive distributed solutions.

The impossibility of delivering excess power to a grid limits the full exploitation of renewable and of co-generation opportunities. Renewable development will be truncated to scales matching the power needs of the end-users on site. Co-generation development will be limited to a capacity corresponding with the share of the heat loads that are covered by complementary power loads, according to the maximised power/heat efficiency ratio of the co-generation technology. This is the best approach economically (Verbruggen, 1996). On sites where the need for useful heat exceeds (several times) the need for power (a situation occurring frequently), this micro-economical rational choice results in a underdevelopment of efficient co-generation opportunities, foregoing thereby the chance of fuel savings and climate change mitigation.

Natural gas is the most commonly used fuel for most new co-generation installations in the industrialised nations. Countries without a link to gas supply networks, or those with only a limited network, therefore face an immediate disadvantage. Even where natural gas is more widely available it can often be too expensive to connect particular sites with distributed co-generation opportunities to the gas supply network (COGEN Europe, 1997b).

Unequal treatment with respect to fuel supplies

Because co-generation technologies are in many countries developed by end-users or by independent power producers they must compete with established pools of centralised generators that benefit from discounted fuel prices. This may be an important handicap to compete with the separate supply of heat or steam by means of boiler fuels and with the separate supply of power through the interconnected power system (Blok and Farla, 1996).

Authorisation and licensing arrangements

Procedures for authorising the construction and the operation of distributed facilities can be bureaucratic, complex and time consuming because most standards were developed for central power production installations. In some countries the investments in power generation are subjected to a particular planning process, involving official hearings by parliamentary or regulatory commissions. For small-scale distributed generation projects, such procedures would mean a significant additional barrier to project development.

Environmental and emission regulations

A small co-generation engine may be treated as a large-scale power producer, having the same (e.g. administrative) obligations in obeying environmental and emission rules. Also the higher conversion efficiency of co-generation may not be credited sufficiently by regulations directed to the conventional power sector. The actual discussion in the EU on subventions yes or no to co-generated power shows that there are diverging opinions on this issue.

Environmental standards also may forbid explicitly or hinder implicitly the use of particular fuels or of particular technologies, overall or on the location of the distributed project. For example, co-generation in the built environment may have to obey very strict standards of flue gas emissions and of noise and vibration levels. Respecting environmental standards may involve significant expenses for abatement equipment.

Grid connection

The connection to the power grid is important for renewable and for co-generation distributed power projects.

Renewable energy mostly is available as a flow of water, wind, radiation or heat (Twidell and Weir, 1986). Except for some water flows, the most essential properties of renewable flows are the intermittence and the diffuse character of the flows. A part of the intermittence is predictable, some part is not. Therefore, the supply of renewable power is governed by stochastic laws, and falls outside the governance by man. The flow of renewable energy is running from the natural sources to the natural sinks whether or not man is making use of this flow. In order to make use of the natural flows one has to position within the flows capture and conversion devices to feed particular end-uses. In principle the resistance created by the devices within the flows should be minimised and the concentration of diffuse energy should be maximised. In other words the capture and conversion devices should be of the highest efficiency. Meeting these challenges requires already significant technical and economic efforts, but does not solve the issue of intermittence. The impact of this latter factor fully depends on the end-uses and end-users served by the renewable plant. When the end-user is willing to float his energy needs along the stochastic supply by renewable sources, the most simple construction is feasible. However in our modern society people is spoiled by the availability of an unlimited supply of concentrated power supply at any moment of time. This provides the feeling of discretionary authority and freedom fostered by cultural trends and advertising businesses. This means that the end-user wants to steer the supply of energy and refuses to be dependent on stochastic supplies.

In still the same setting of natural flows with a capturing-conversion device installed in between, the end-user can exert a negative feedback control at the entrance of the capturing or at the exit of the converter. This control makes that surplus power in the flow, i.e. power that the end-uses cannot absorb, will be spilled and that a share of the expensive capacity is idle. When moreover end-uses need more power than the nameplate capacity of the devices or than the current power in the natural flow available, the feedback control cannot meet the gap. Either end-users adapt their needs to the limits of nature and devices, or one must develop other solutions.

Two solutions are possible. The first is the addition of storage capacity to the capturing-conversion devices. The second is the organisation of an intelligent feed-forward control system. We will see at the end of this chapter that the grid offers both solutions.

By adding a facility that can store the captured and converted renewable energy flow in between the capturing-conversion device and the end-uses, feedback control by the end-user can reduce the spill-over of energy flows while at the same time reducing the required capacity of the device itself. The major problem is that power by its very nature is non-storable, and that “power storage” involves a linked process conversion-storage-conversion. Investments and operational losses go along. Storage solutions are developed when no alternatives are available, e.g. in isolated settlement conditions.

Intelligent feed-forward control involves that end-users are supplied when renewable power is available. This approach is comparable with the most basic application of renewable power we discussed at the start of this chapter. The difference however is that intelligent feed-forward puts several end-users in parallel, manages their loads, ranks the users in merit order, and meets the loads accordingly. By this intelligence one tries to harvest the full flow of renewable energy. It requires a full control over the end-uses.

In real life systems of renewable power, one will find it most easily not to invest in storage facilities, nor to set up a complex feed-forward control, but to connect to the bypassing power grid. This means the grid is placed in between the own capturing-conversion devices and the own end-uses. It plays the role of an infinite storage facility with respect to the distributed generation capacity although in reality delivered power to the grid is not stored but is replacing other generation (Hoff et all, 1996). As long as the aggregate delivery of distributed (and non-despatched) power to a grid falls short of a significant share of total power generation, substitution is feasible. When the aggregate becomes very large compared to the grid dimensions, one will have to turn again to the two basic solutions discussed above: ‘power storage’ and intelligent feed-forward control. By that time the latter approach may be available although it requires an unprecedented level of end-use governance. A mix of both solutions will always be necessary, and in the meantime the terms of grid connection determine to a large extent the future of renewable power.

The terms of grid connection

Every distributed generation project should benefit from being linked to the interconnected power grid, because this provides the advantages of being integrated into the extended electricity "market". There have been witnesses of technical, economic and institutional rules and practices that limit a fair access to the grid for distributed generators. In many nations these barriers have proven to be the most oppressing factor to the development of independent renewable or co-generation opportunities.

Position and attitude of the grid operator

In many power supply systems by now, there is not yet an independent system operator available that balances the offers from the various competitive suppliers. Mostly the system operator was (and in many countries still is) a part of a vertical integrated electricity supply company that moreover enjoys a monopoly position. When such electricity monopolies function within a regulatory environment of making profits proportional to electricity sales volumes, distributed generation will be approached as a loss of sales that should be avoided on all occasions (Rüdig, 1986). In the USA and in some other nations, the regulators have imposed the obligation of Integrated Resource Planning on the utilities, requiring an equal treatment between the own central and other man's distributed generation sources (Thomas et al, 2001). The success of IRP is not guaranteed without a very strict regulatory supervision out of reach of most countries in the world. In general the attitudes of the central electricity systems have been hostile towards distributed generation initiatives (Dufait, 1996).

In liberalising the electricity markets, an independent system operator should be installed to organise the transactions in the electricity (bulk) market. This may result in a more neutral approach of distributed generators, and in a levelling of the barriers impeding a smooth access to the power markets. These other barriers are discussed hereafter (COGEN Europe, 1997b).

Technical barriers

Incumbent power companies sometimes impose very heavy regulations on producers or industries that file for a connection to the electric grid. On occasions the demander is requested to install a separate link to the next-by transformer station in the grid. The connection, the metering, the safety equipment, etc. all may be extra-ordinarily loaded to discourage independent producers. Especially small institutions and companies can be scared off by technical prescriptions that cannot be met in standard packages.

Tariff conditions

There are three types of power flows that can be exchanged between an independent producer and the grid (Verbruggen, 1990, 1996).

1) Surplus power that the distributed generator delivers to the grid.
2) Shortage power bought by the distributed generator at the grid: make-up (additional, complementary).
3) Shortage power: back-up for a failing distributed plant.

The tariff conditions are a particularly difficult issue, because the value of a kWh is dependent on the time, the place, the quality, the reliability and the liability[32] of supply. Therefore it mostly is true that a kWh from the central grid is of higher value than the kWh supplied by a particular distributed generator, but it is also true that the applied prices to both kinds of kWh are mostly far more apart than their real values are.

The tariff conditions are very crucial and dominantly determine the growth opportunities of distributed generation facilities.

Tariff conditions are a result of the interplay between on the one hand technical and economic realities and on the other hand institutional and political deliberations. While time, place, quality and reliability of electricity supply can be measured in a technical way, the liability aspects are more the subject of evaluation and opinion, dominated by organisational and political power.

Surplus power

The remuneration of surplus power is based on the principle of 'avoided costs' by the grid-system (Fox-Penner, 1990). Although this principle is widely accepted, its implementation is set back by theoretical and practical difficulties in defining and measuring the avoided costs. In practice, one should measure the instantaneous marginal cost of the integrated power supply system taking into account generation plants' constraints, grid constraints and reliability aspects. When the electricity markets are liberalised, competition may bring the kWh-price near to the marginal costs of its supply.

Regulated 'avoided costs' prices and competitive marginal cost prices will entail an impediment to the development of distributed resources, when the latter generate electricity at a higher marginal cost. This can be due to a number of factors. First, the central power supply may be subsidised. Second, the central system may be run on hydro-power or on nuclear power, that are both characterised by low short-run

[32] Liability of supply is related to the 'obligation' to supply power when demand occurs and to the 'impossibility' of supply when demand does not occur. Central power systems meet a high degree of liability, while distributed generators mostly are characterised by a low degree of liability. In effect, most distributed plants are non-despatched and deliver power to the grid when they generate a surplus above the own needs while at the same time they are not ready to supply (additional) power when the grid would ask for it. Power delivered on request by the customer is more valuable than power delivered on decision by the supplier.

marginal costs. Third, central power systems may face significant over-capacities in generation plant that depress short-run marginal costs below the long-run ones. Fourth, the marginal cost of electricity transport over the grid may increase because of growing power trade and because of difficulties in getting licences for new lines. Of course, the latter constraint should imply stimuli in favour of distributed resources, but this is not reflected in the pricing of delivered surplus power by the distributed generators.

Shortage power: make-up

Make-up power is the power in top of the own production required by a distributed generator for meeting the own end-uses. Depending on the heat and electricity load profiles, the amount of make-up power tapped from the grid may be large or small, stable or fluctuating over time. In principle, make-up power should be billed to the distributed generator at the same tariffs conventional customers are charged. This is not always the case, because in some countries make-up power is charged at special rates based on arguments that make-up power shows more irregular load profiles than normal electricity demand.

Shortage power: back-up

When the own generation plant is in forced outage most distributed generators will want to tap power from the grid, especially when the end-uses serve processes of high value or urgency. In many systems back-up power supplies by the grid carry high prices. This is the result of the joint occurrence of on the one hand applying the overall customer tariff on the back-up supplies, and on the other hand the property that most of these non-linear or block tariffs encompass a high fixed (per kW) term. The appeal during very short duration on a significant back-up capacity will be charged then the full fixed term, what may involve a deadly bleeding for a distributed generation project. In principle, the distributed generator should have access to spot power priced accordingly or to contracts for reserve power taking into account the insurance costs that distributed generation imposes on the central system.

High wheeling charges

On some occasions, distributed generators may want to wheel power over the grid to related companies or to customers that are willing to pay a higher price for the surplus power or to producers that are charging a lower price for shortage power. These transactions are impeded when transporting power over the grid is loaded with predatory tariffs.

Energy policy

The terms of grid connection and grid interaction are crucial for the future of distributed power generation. Unfair systems cause economic efficiency losses inflicted on society, and make policy instruments ineffective, e.g. subsidies that policy makers assign to renewable energy projects, can be stripped off by vested power companies that control the conditions of grid connection. Of course, this outcome is not the target of the policy makers. Market reform can improve the terms of grid connection or it can blow up particular existing preference rules that were set up for promoting distributed power. A few years ago it was expected that distributed generation would develop more fully when electricity markets were opened to competition that brings more exit and entry opportunities and more choice for market participants (COGEN Europe 1997b). Competition should develop power tariffs reflecting the short-run marginal costs of supply. It should bring forward ranges of contracting opportunities (e.g. also covering reserve power deliveries) and it should free the access to the electricity transmission grids for third parties. However, fair competition in the electricity sector must be organised by enlightened regulators. Firm public policy and regulatory authority are necessary to install and safeguard harmonised conditions for all participants, transparency of the processes and unbundling of the main power supply functions. Most countries today still lack the intellectual and administrative capabilities for the foundation of authoritative regulatory services. This will lead to sub-optimal returns from the liberalisation process for options such as distributed generation and co-generation.

The final settlement of grid conditions is the result of the interplay between technical and economic factors on the one hand and institutional and political deliberations on the other hand. The latter deliberations can bring forward solutions that subsidise or want to subsidise distributed solutions (e.g. the system of green certificates or regulations stimulating the development of co-generation). Because of the environmental benefits of renewable and co-generated power, this policy is justified. However, we argue that one always should try to keep situations, proposals and solutions transparent. On the one hand, the fair terms of grid connection should be spelled out. On the other hand, the subsidy measures should be stated and their interaction with the former terms studied. This way of discussion has at least two advantages. First, it helps to avoid situations where the subsidies are ripped off by grid owners or by incumbent power companies. Second, it keeps the minds clear for eventual changes in the terms of trade with the grid in the future. Distributed systems that are not robust for such changes, should receive lower priority than systems that are robust.

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Impact of the new Swiss electricity law on the competitiveness of hydropower[33]

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Keywords. Hydropower sector, deregulation, electricity market law, long-term competitiveness, cost structure

Abstract. Although Switzerland is not a EU-member country, in December 1999 the Swiss Parliament adopted the new Swiss Electricity Market Law (EML). The EML laid the foundations for reforming the Swiss electricity industry by moving from regulation to deregulation. The Swiss population will vote on this issue in late 2002. This change will be phased in gradually during a transitional period of seven years. This paper briefly describes the Swiss electricity industry and details the reform plans set out in the law. It also analyses the impact of EML on the hydropower firms and offers an overview on the competitiveness of the hydropower sector in the deregulated market.

Introduction

Over the past two decades many EU-member countries have legislated either a gradual or full opening of their electricity markets. This process was begun in accordance with member countries' obligations to implement the EU Electricity Directive 96/92/EC no later than February 1999. Although Switzerland is not an EU-member country, in December 1999 the Swiss Parliament adopted the new Swiss Electricity Market Law (EML). However, this Law has since been submitted to popular referendum.[36] Therefore, the Swiss population will vote on this issue in late 2002, and, if the EML is approved, the Swiss electricity market will be deregulated on January 2003. The EML lays the foundations for reforming the Swiss electricity industry by moving from regulation to deregulation. This change will be phased in gradu-

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33 This article is based on a report written for the Swiss Federal Office of Energy, Bern (Filippini et al., Perspektiven für die Wasserkraftwerke in der Schweiz – Langfristige Wettbewerbsfähigkeit und mögliche Verbesserungspotenziale, December 2001).

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36 Federal laws, generally binding decisions of the Confederation, and State treaties concluded for an indefinite duration are subject to an optional referendum: in this case, a popular ballot is held if 50,000 citizens request it. The referendum is similar to a veto and has the effect of delaying and safeguarding the political process by blocking amendments adopted by Parliament or the Government or delaying their effect.

ally during a transitional period of seven years. Today in Switzerland some fear that this reform will adversely affect the economic and financial situation of the hydropower plants.

The purpose of this paper is to detail the reforms plans set out in the EML and to offer a first overview on the possible impacts of the reform on the competitiveness of the hydropower sector.

The article is organized as follows. In the next section we briefly present the Swiss electric power industry. After that the main elements of the Swiss Electricity Market Law are discussed. The possible economic effects of the introduction of this Law on hydropower sector follow in section 3. Section 4 concludes.

The Swiss electric power industry

The Swiss electric power industry is composed of about 1,170 firms, public and private, that are engaged in the generation, transmission and/or distribution of electric power. There is great diversity of size and activity among these companies. Generally, we can distinguish three types of electric companies. The first type is characterized by companies that generate and transmit electricity. The second type is represented by electric companies that primarily distribute electricity. Finally, the third type of company performs all three electric power system functions and is vertically integrated. Table 1 presents an overview of the composition of the Swiss electricity industry.

Table 1. Number of electricity companies in Switzerland (1997)

Generation and/or Transmission	90
Generation, Transmission and Distribution	140
Transmission and/or Distribution	940
Total	1170

Source: VSE, The Swiss Electricity Supply Industry Development and Structure, 1997.

In the first group of companies we also find the so-called partner company, where shareholders can claim electricity production in proportion to their share of capital. These partner companies are hydropower plants (storage) located in the Alps.

In terms of numbers, utilities exclusively engaged in the distribution of electric power are dominant, comprising 74% of the total. The majority of these 900 or so companies are municipals and provide power to their communities exclusively. The remaining utilities operate within urban or regional areas. Part of this group of firms is involved in generation, transmission and distribution, but generally the amount of generated power is small and is determined by the ability to exploit favorable hydroelectric power generation possibilities. There are few vertical integrated utilities that generate a large amount of power. The municipal and regional electric utilities purchase power mainly from the nine largest overland companies, which form the backbone of the industry. These larger vertically integrated companies provide most of the generated electricity and are also involved in the transmission and distribution of electricity to final consumers and municipal utilities. Moreover, these dominant companies own and control the trans-regional and the international grids, which are planned and used in close cooperation. This means that these companies are the relevant international actors for the exchange of electric power with neighboring countries.

The characteristics of Swiss electric power generation are best illustrated with the aid of Table 2.

Table 2. Characteristics of Swiss power generation sector (2000)

Type of power plant	Installed capacity MW	Installed capacity in %	Annual electricity production Gwh	Annual electricity production in %
Hydro (Run-of-river)	3570	20.8	17566	26.9
Hydro (Storage)	9600	55.9	20285	31
Nuclear	3200	18.6	24949	38.2
Thermal power plants and others	790	4.7	2548	3.9
Total	17160	100	65348	100

Source: Schweizerische Elektrizitätsstatistik, 2000, Swiss Federal Office of Energy, Bern.

The Swiss electricity sector is almost exclusively based on hydropower generation (~58%) and on nuclear power generation (~38%). The production of electric power using thermal power plants or wind or photovoltaic energy is still limited (~4%). Run-of-river hydro power plants and nuclear power plants are principally utilized to satisfy the electricity demand at the national level during the medium and low load periods, whereas the storage and the pumped storage power plants are employed to satisfy the electricity demand during the high load periods.

The Swiss Electricity Market Law (EML)

With the introduction of the Electricity Market Law, the electricity sector of Switzerland will be reformed by moving from regulation to liberalization of some parts of the industry. At the end of the process, all customers will have the option to choose their energy supplier. The Swiss Electricity Market Law rewrites the rules that have traditionally governed all electricity-related activities in Switzerland. The basic principles of this law involve turning generation and retailing into competitive activities and allowing free access to the transmission and distribution grids, which will remain regulated activities.

The main characteristics of the EML include the following:

1) A system of regulated third-party access to the networks and therefore wholesale and retail competition.
2) Organisational unbundling of electricity transmission at the extra high voltage level and other activities. As part of the regulatory reform, the high voltage transmission grid will be disinvested by the seven firms (*Ueberlandwerke*) cur-

rently in control of the national grid. The national grid will be organised as a private company with the function of an independent system operator (ISO).

3) Separation of accounting for generation, distribution/retail supply and non-electricity related activities.
4) The creation of a new institution, the Arbitration Commission, to act as an independent agency with responsibility for supervising transmission and distribution tariffs.
5) A system based on bilateral contracts freely negotiated between buyers and sellers; therefore, a system without an independent system operator (ISO) that operates a centralized spot market.
6) Power exchange with other countries based on the adoption of a reciprocity clause. However, a safeguard clause in the law ensures that access to the grid can be refused to suppliers from countries with less liberalised electricity markets.
7) The EML allows qualified consumers to choose their electricity supplier. This element of the reform will phased in. In the first phase (first 3 years) of the introduction of the reform the distribution companies will have the possibility to choose their electricity supplier for 20% of their supplies. Whereas in the second phase (second 3 years) of the reform this share increases to 40%. After six years, the electricity market will be fully open to competition, which goes beyond the requirements of the EU Electricity Directive.

The cost structure of the Swiss hydropower industry

Although at the moment it is uncertain when the new electricity market law will be in force, some fear that power prices in the next years will decrease and that this decrease could have a negative impact on the financial situation of the hydropower producers. In order to analyse this impact, the Swiss government and the Swiss Electricity Supply Association have commissioned some studies on the issue of stranded investments due to the deregulation process.[37]

In this paper, we employ another approach to analyse the impact of the EML on the competitiveness of hydropower firms. Our study is based on the comparison of the actual cost structure of a sample of hydropower firms with the expected market prices for the next ten years. In our analysis a firm is competitive in the short-run, and therefore, does not shut down, if the market price is equal to or higher than the minimum of its average variable costs.[38] This definition, considering that the majority of the Swiss hydropower firms will renovate their plants only after 2020, seems, from the economic point of view, appropriate.

Our analysis is based on the assumption that the cost structure of enterprises will not change significantly over the next decade. This seems quite reasonable since in recent years - in view of market liberalisation - important improvements in cost efficiency have been achieved. Operational costs (wages and maintenance) especially have been lowered.

In addition, the potentials for capital cost reduction have been, as far as possible, exploited. Producers have carried out extraordinary depreciations, since they fear that in a liberalised market power prices will not be high enough to allow for an amortization of plants. Enterprises are largely unable to reduce interests' payments on debt capital, since the capital market fixes interest rates. Consequently, it can be observed that interest payments vary according the development of interest rates, increasing during periods with high interest rates and decreasing when the interest rates fall.

Dataset

The analysis of the cost structure is based on a dataset containing technical and economic information for a sample of **46 producers**[39]. The dataset contains economic information derived from the annual reports of the producers for four years (1990, 1995, 1997, 1999), whereas the technical data are available for the year 1999. One major difficulty was to find meaningful criteria to allocate enterprises that generate electricity from several different types of plants to one specific hydropower category.

For the analysis the following categories of hydropower plants were defined and allocation criteria used:

1. Hydropower producers with an installed capacity between 1 and 10 MW: This category includes all firms producing more than 50% of their power with plants that have an installed capacity between 1 and 10 MW. This category usually has higher specific investment costs (costs per installed kW) and is therefore analyzed separately.[40]

2. Run-of-river hydropower producers (exploitable drop below 25 m): This category includes all firms that produce more than 50% of their power with run-of-river plants having an exploitable drop below 25 meters. These plants have no storage capacity and therefore have to produce continuously according to the river's seasonal and annual flows. Run-of-river plants with a small difference in elevation (less than 25 m) between catchment area and turbines are usually located along the large rivers in

[37] Estimates of stranded investment of the electricity sector in Switzerland have been carried out for example by econcept (1997) and CSFB (1997)

[38] In this analysis, due to the very long run character of the hydropower investments, short-run means 5 to 10 years

[39] From the original dataset we had to eliminate all those enterprises that are producers and distributors. At the moment it is not possible to discern the share of the costs of each activity.

[40] Elektrowatt 1998

the flat parts of the country. Further, they generate power constantly over the year.

3. Run-of-river hydropower producers (exploitable drop above 25 m): This category includes all firms that produce more than 50% of their power with run-of-river plants having an exploitable drop above 25 meters. This category contains mostly the run-of-river plants located in the mountainous regions of the country. Usually, these plants exploit the large altitude differences between the catchment area and the location of turbines. The water is usually led into pressure conduit systems. These producers often have problems with minimal flow requirements in the downstream reaches (between the point of catchment and the release of water into the river). Their power generation is larger during the summer period (higher flows of the mountain's rivers).

4. Producers using storage plants without pumps: This category contains all firms that produce more than 50% of the power with "pure" seasonal storage plants. They are usually located in the alpine regions of the country. Their investment costs (costs per installed kW) are significantly higher than those of run-of-river plants. These additional costs are compensated for by focusing production on peak demand hours.

5. Producers using storage plants with pumps: Firms assigned to this category use pumps whose capacity reaches more than 8% of the capacity of the turbines. The presence of pumps has an impact on investment costs (costs per installed kW). On the other hand, the water pumped in the reservoir during the off-peak period can be used to generate electricity during the peak-load periods, increasing the enterprise's revenues.

Table 3. Characteristics of the sample (data for the year 1999)

Categories	# of firms	# of plants	∅ Installed capacity MW	∅ output in GWh
1-10 MW	5	8	5	24
Run-of river (drop <25 m)	7	8	59	346
Run-of river (drop >25 m)	11	27	91	342
Storage without pump	11	27	217	434
Storage with pump	12	58	553	884
Total sample	**46**	**125**	**185**	**406**
Total Switzerland	311	525	45	110

The sample includes 46 firms with 125 power plants. Considering that in Switzerland there are 525 hydropower plants with a capacity of more than 1 MW, our sample includes about one fourth of all these plants.

The figures in Table 3 show that the average size of the plants considered (185 MW) is much higher than the Swiss average (45 MW, only plants above 1 MW capacity). Consequently, the average power generation of the plants is much higher than the Swiss average (sample: 406 GWh; Swiss average: 110 GWh). In total, the sample plants generate more than 60% of power produced in Switzerland. Looking at the different plants' categories, storage plants with pumps have the largest average capacity (553 MW) and annual generation (884 GWh). By contrast, the storage plants without pumps considered in the sample are considerably smaller and produce about half as much power as storage plants with pumps. The two categories of run-of-river plants have very similar output levels, although some differences in their average capacity can be observed. Finally, the average installed capacity as well as the average output level of plants between 1 and 10 MW is very low, according to the definition of this category.

Actual cost structure

Fig. 1 shows the costs structure for the five categories of hydropower plants. The hydropower plants with a capacity between 1 and 10 MW have the lowest costs per kWh. Further, the run-of-river plants have below-average costs. In contrast, the production costs of hydropower plants with storage possibilities are above average.

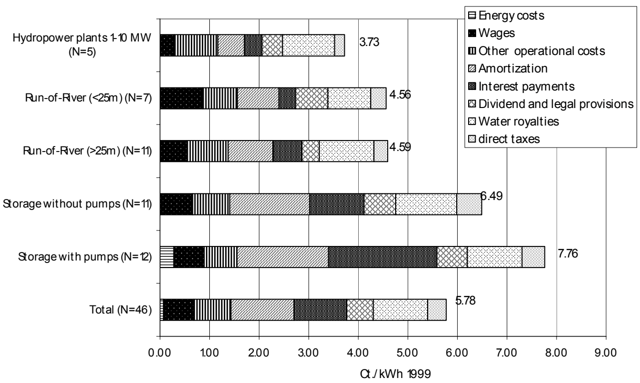

Fig. 1. Production costs for different categories of hydropower plants (1 CHF = 0.67 €)

Over all categories, the variable costs of power generation – wages, energy and other operational costs – amount to 27% of total production costs, while 46% are related to capital costs (interest payments, amortizations, and legal provisions). This share is higher for the high capital-intensive hydropower plants with storage, where this costs' category is responsible for more than 50% of total production costs. Finally, 27% of overall production costs are related to water royalties and taxes. This share is higher for those plants with low operational and capital costs (i.e. plants with a capacity between 1 and 10 MW and run-of-river plants).

Variable costs and output level

In order to identify the factors decisive for the level of production cost of firms, it seems reasonable to look at the variable and the fixed production costs separately. We assume that different elements affect the level of these two cost categories.

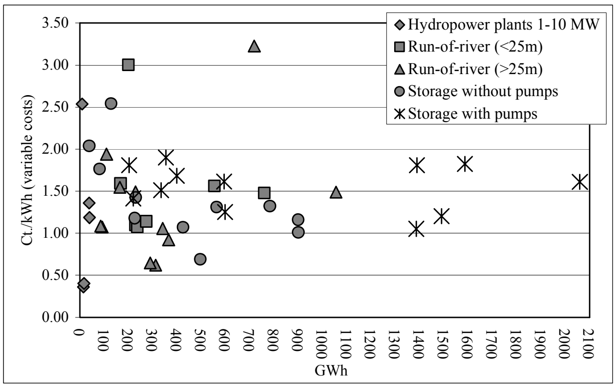

Fig. 2. Relationship between output and specific variable costs of production (labour, energy and other operational costs, 1 CHF = 0.67 €)

Fig. 2 illustrates the relationship between the variable production costs and the annual power generation (in GWh) for the five categories of hydropower plants. The level of variable costs varies considerably, between categories as well as between plants of the same category and with similar levels of production (see for example the variable production costs of storage plants with pumps). Within the same category of power plants variable production costs vary by a factor of two or more. These differences can be explained either by site-specific characteristics - and thus differences in the maintenance of the plants - or by different efficiency levels.

Storage plants with pumps show decreasing variable costs with an increase in output level. For the other categories this relationship seems to be weaker.

Given the small number of enterprises considered in each category, these results are to be interpreted carefully. In the next step of analysis we plan to carry out econometric analysis with a larger sample in order to identify more definitively the presence of economies of scale in production.

Capital costs

Investments in new storage plants or in enlargement of existing plants imply considerable investment costs (costs per installed kW). These can be compensated for either by an increase in the output level or by a change in the production pattern i.e. an increase in peak load generation (an increase in the average market price).

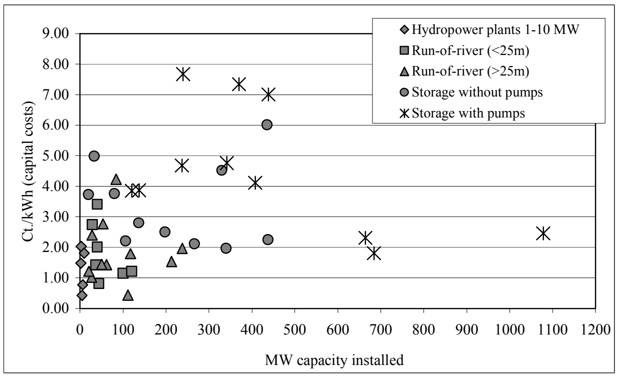

Fig. 3. Relationship between capacity installed and specific capital costs (amortization, interest payments, dividends, legal provisions, 1 CHF = 0.67 €)

Fig. 3 shows the relationship between specific capital costs (sum of amortizations, interest payments, dividends and legal provision) and installed capacity.

On the one hand, increasing capacity implies higher capital costs: investment costs (costs per installed kW), and therefore amortizations and interest payments, are positively related to the capacity installed. On the other hand, this cost-increasing effect can be partly offset by an increase in the production level.[41] Probably because of the small sample, it is difficult to identify clearly how capital costs vary with the capacity installed.

Fig. 4 illustrates the development of specific capital costs according to the age of the plant (years since plant construction). As expected, specific capital costs are lower for older plants. This can be explained by the fact that a larger share of the value of the plant has already been depreciated.

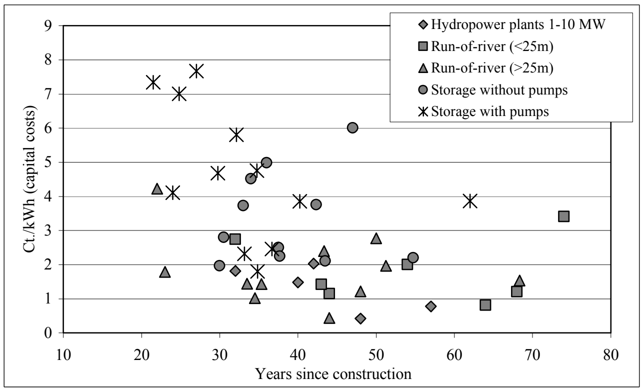

Fig. 4. Relationship between year of construction and specific capital cost (amortization, interest payments, dividends, legal provisions, 1 CHF = 0.67 €)

Comparison of the production costs with the expected prices

In this part of the paper we compare the specific actual costs of the hydropower firms in our sample with the expected power prices for the next years

[41] One objective of an increase in the capacity installed can be an increase in production in peak load periods, leaving the total annual production unchanged.

(Table 3, prices expected by Swiss producers). This comparison will show whether or not some firms from our sample will be able to cover their variable costs. From the theory we know that in the short run, hydropower plants will operate as long as electricity market prices cover at least the variable costs of production.

Table 3. Forecast of electricity market prices (1 CHF = 0.67 €)

Period	Peak (Cts./kWh)	Off-peak (cts./kWh)
2003-7	5-6	3-4

Source: Econcept (1997) and information of Swiss electricity producers

On the basis of our sample of 46 enterprises, it is possible to look in more detail at the production costs and average prices of each enterprise.

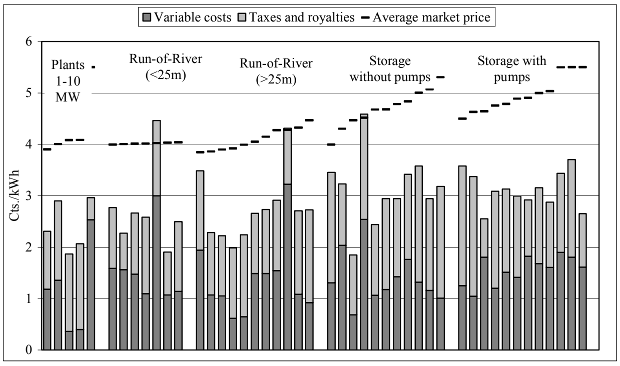

Fig. 5. Variable specific production costs and average market prices of the enterprises in the sample (N=46), peak market price: 5.5 Ct./kWh; off-peak price = 3.5 Ct./kWh (1 CHF = 0.67 €)

Fig. 5 shows the variable production costs as well as the costs of taxes and water royalties and, as indicated by a thin line, the average market price of enterprises. We calculate the average price taking into consideration the production structure of enterprises. For storage plants we have assumed that production takes place primarily in peak periods and only secondarily in off-peak periods. Run-of-river plants are not able to adapt production to the different load periods. Therefore we assume a constant production pattern across the day and the year[42]. The output in each load period is priced according to its corresponding market prices (Table 3).

If we compare the expected short-run prices with the variable production costs (including taxes and royalties) we see that the great majority of enterprises will be able to cover at least their variable costs. Only those producers with the highest specific operational costs will have difficulty covering them.

Since small plants (with capacities between 1 and 10 MW) have low operational costs they do not seem to incur such problems in the short run. The same holds for the storage plants with pumps. Although they have higher average operational costs, the prices they achieve are also higher than those of run-of-river plants. The other categories have only a few enterprises with variable costs above or near average prices. For a majority of enterprises, the difference between specific variable costs and prices is high enough to allow for small variations in price level or costs without having an impact on the short-run decision of whether or not to generate.

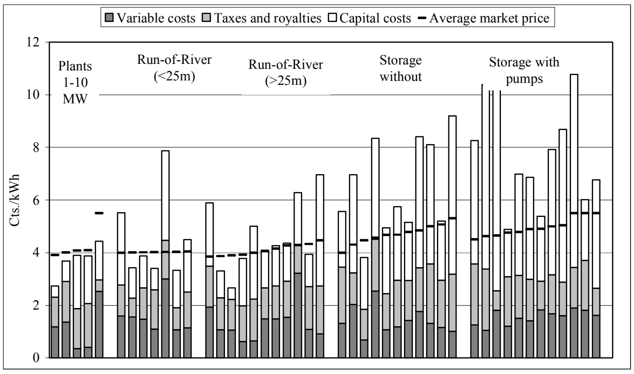

Fig. 6. Total specific production costs and average market prices of the enterprises in the sample (N=46), peak market price: 5.5 Ct./kWh; off-peak price = 3.5 Ct./kWh

Including the capital costs obviously dramatically changes the situation concerning the economic performance of enterprises.

Although the specific costs in Fig. 6 could represent an upper limit of effective capital costs (due to extraordinary amortization carried out in view of market liberalization), several enterprises will not be able to cover their capital costs. Particularly among the capital-intensive storage plants with pumps, the forecasted market prices could imply important stranded investments.

Conclusion

The new Electricity Market Law will bring about a liberalization of some parts of this industry. It is expected that in the short term, in a European market situation characterised by over-capacities, power market prices will fall. As a result, some fear that Swiss hydropower plants will encounter economic and financial problems and, in the worst case, could be obliged to shut down.

An analysis of the cost structure of hydropower plants and a comparison of the expected specific revenues with production costs yields the following conclusions:

1) In the short run only a few producers will have financial difficulties covering operational (variable) costs. Therefore, the majority of the Swiss hydropower firms will not shut down their activities.
2) Some firms of our sample present very high variable costs. We believe that these firms have the potential for optimisation and efficiency increases.

[42] We consider the differences between hibernal and summer production levels.

3) In the short run several power plants will be unable to cover the full production costs. Capital-intensive hydropower plants (plants with storage) will be particularly affected.
4) In the long run, the competitiveness of the hydropower sector will be determined by the capability of the producers to renovate, and therefore to re-invest in, their plants. The expected long-run market prices will be decisive for these investment decisions.

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Programme

Thursday, 16 November 2001
Electricity Markets
(Chair: Roman Čížek, SRCI, Prague

9:00	**Opening of the ENER Forum** Jan Pouček, Director of Energy Policy Dept., Ministry of Industry and Trade, Czech Rep.
9:15	**European Research Area: The scientific basis for EU policy making** D. Rossetti di Valdalbero, DG Research, European Commission

Session 1: The Internal Electricity Market: Implementation of the EU Directives
(Chair: Roman Čížek, SRCI, Prague)

9:30	**The EU Electricity Directive: the EU Commission's proposals on completing the internal electricity market** Patrick Rousseaux DG TREN, Unit C2
10:00	**The Industry's View of Liberalisation : EURELECTRIC's experience to date** Inge Pierre, Vattenfall and Chairman of Eurelectric SG on "Quality CHP".
10:30	**Coffee break**
11:00	**Introducing competition in Western Europe: a critical review** H. Auer, TU Wien, Energy@Econ. Group, Austria
11:45	**Options and potentials for European electricity imports and exports: a German perspective** C. Cremer, FhG-ISI, Germany
12:30	**Discussion**
13:00	**Lunch**

Session 2: Implementation in Accession Countries
(Chair: Eugene D. Cross, ECN Policy Studies/ University of Leiden, the Netherlands)

14:00	**Implementation of the EU Directives in Hungary** P. Kaderjak, Director General, Hungarian Energy Office, Hungary
14:40	**Implementation of the EU Directives in the Czech Republic – the Regulator's view** P. Brychta, Head of Energy Regulatory Office, Czech Republic
15:20	**Tea break**
15:50	**Polish progress in the implementation of the EU Gas and Electricity Directives** K. Bolesta, Office of European Integration Poland
16:20	**Development of Romanian electricity market** George Lavrov , ISPE, Romania
16.50	**Discussion and closing of the day**
19:30	**Dinner (New City Brewery)**

Friday, 16 November 2001:
Gas Markets and Clean Electricity

Session 3: Implementation of the EU Gas Directive
(Chair: Frits van Oostvoorn, ECN Amsterdam)

9:00	The **EU Gas Directive: objectives and progress in the implementation** P. Rousseaux, DG TREN, European Commission
9:30	**Gas supply security in the EU** G. Greving, Gasunie Netherlands
10:15	**European gas supply in a competitive market** P. Claus, Eurogas
11:00	**Coffee break**
11:30	**Assessment of the European gas markets liberalisation and integration: a critical review** D. Finon, IEPE Grenoble, France
12:00	**Analysis of the Czech Gas Market** V. Stepan, ENA Ltd., CR
12:30	**Implementation of the Gas Directive in Romania** S. Furlan, ENI, Italy
13:00	**Lunch**

Session 4: Green and clean electricity
(Chair: W. Eichhammer, Fhg-ISI, Germany)

14:00	**Green Certificates in the EU context** M. Boots, ECN, the Netherlands
14:30	**Obstacles and opportunities for distributed power generation** A. Verbruggen, UFSIA, Belgium
15.00	**Impact of Swiss electricity law on competitiveness of hydropower** S. Banfi, CEPE, Switzerland

15:30 Final Discussion and closing of the ENER Forum 2

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