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INTERNATIONAL ASSOCIATION *for* ENERGY ECONOMICS

IAEE Newsletter

First Quarter 2008 International Association for Energy Economics

President's Message

It is an IAEE tradition to start the year announcing our Conference Program and wishing great success to new and old members. I think that in this difficult and turbulent period, this wish should be especially relevant. But, before introducing our Program for 2008, let me explain why.

I would like to remind you that as a long standing organisation of professional economists, dealing with the fascinating and complex world of energy, IAEE has always been at the frontier of analysis, research, discussion and understanding of what is going on around the world. As Energy Economists, we are part of the larger family of researchers and professionals who try to understand where and why supply and demand cross and what affects and disturbs equilibrium prices and quantities.

In energy markets, determinants of equilibrium outcomes are complex, typically long-term, very technological, and highly volatile. But overall, energy markets have a special feature which we cannot pretend not to see: they are heavily influenced by geo-political events.

We cannot fake blindness in the face of terrorism, strategic and opportunistic behaviour, military menace, and government involvement, when they plain interfere, in everyday market functioning.

Sometimes, the prudent economist assumes all the above as "exogenous" and carries on. Many times this is a very sensible and humble approach: we economists should refrain from tainting our practical analysis with political or sociological value judgments, taken from today's newspaper, without using the same scientific rigor that we use for abstract economic modelling. After all, we economists are ready to raise our eyebrows, for instance, when politicians fail to appreciate the difference between a bond and a derivative.

Nonetheless, in these turbulent times, we -- Energy Economists -- can have a role in trying to explain and understand future trends of world economic and social development.

The fact is that energy has become scarcer and more valuable for all 6 billion of people in the world.

Is it not the Energy Economist who warns continually that 1.6 billion people worldwide nowadays are deprived of electricity usage? Are we not those who warn that renewables are a technology to pursue, but that with today's level of technology there simply isn't enough for all? Moreover, it is the Energy Economist who is pragmatic enough to do the calculation of nuclear power plant profitability, including direct costs, hidden costs, financial options, delays, uncertainty, decommissioning indirect costs, detached form political passions of supporters and opponents.

Obviously, I do not have the answers to these problems. But our Conferences are the right place to pose the right questions (for sure!) and get the right answers (maybe!), because the intellectual stance of participants, the generosity of the organisers, the competence of the speakers are excellent.

In 2008, for the first time in the history of IAEE, we are organising a Regional Conference in Africa, which will take place in Abuja, Nigeria at then end of April. Next, in June we shall hold our International Conference in Istanbul, Turkey. Two more Regional Conferences will follow: in November in Asia (Perth, Australia), and in December in North-America (New Orleans).

I would like to hold a Council Meeting, if possible, concurrently with each Confer-

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Editor: David L. Williams / Contributing Editors: Paul McArdle, Tony Scanlan and Marshall Thomas

ence, to give impetus to our ongoing discussion, to steer the future direction of our organisation. We have a strong student program, but we should intensify our outreach in academic campuses. We keep reaching new members in new parts of the world, but I would like to pursue an even greater ambition: expand IAEE presence toward the east of Western Europe; I mean, Russia and China. It would be extremely valuable for our organisation to welcome the great intellectual and professional contribution of our Russian colleagues: energy economists in academic, professional, business, and government roles.

Our Conference program is expanding. Are we going in the right direction? Attendance and the impact of papers presented will provide the answer. But at IAEE we are confident that it is the right choice: we need to search for new facts and understanding, to discuss uneasy issues, to provide occasions of dialogue even when it may appear useless. And we want to do it in new areas of the world.

The economic profession deals with teaching in classrooms, uses theoretical paradigms such as perfect competition, efficient allocation, and endogenous growth. But in the fascinating energy world, there are some provocative questions which challenge textbook economics.

First of all, is the functioning of the world oil market efficient? In the industrial economies we have developed sophisticated antitrust legislation to prevent monopolies or oligopolies that deprive consumers from efficient allocation, which is typically signalled by the equality of marginal cost and price. In the telecommunication industry, antitrust principles have been heavily applied in the U.S. European Antitrust has been extremely severe on software producers. Airline managers who talk about price fixing have been sentenced. All this has some justification: only competitive markets allocate resources efficiently. So the question is: in the oil market, are international cartel meetings pursuing efficiency?

Secondly, in Europe, (unlike in the U.S.), the international gas market is highly asymmetric: on the demand side there are 400 and something millions of consumers, while on the supply side, there is essentially only one government controlled company. In such instance, is it efficient to pursue liberalisation of internal gas networks in Europe? What is the real benefit for the European consumer of monopsonistic national companies which control the network, as opposed to the benefit of having unbundled national networks, which have to compete at the EU border for the same gas?

Thirdly, economic theory affirms that efficient markets develop technological innovation and adequate investment. In this respect, is innovation investment in energy enough? I would like to remind you that in 1878 a certain Mr. Thomas Edison invented a device to record the human voice. At that time, a heavy desktop drum was able to reproduce, in trembling fashion, the short sentence: “Mary had a little lamb”. After roughly a century, a pocket-size small Ipod can store all the music composed by Mozart in his entire lifetime. The rate of technological progress has been immense: possibly million-fold.

Well, in the same year, 1878, the same Mr. Edison invented the light bulb. In the year 1908 Einstein discovered the photovoltaic principle. He won the Nobel Prize.

When shall we witness a renewable source with multiple (rather than fractional, incremental) efficiency, with respect to Edison and Einstein inventions?

Andrea Bollino

IAEE Mission Statement

The International Association for Energy Economics is an independent, non-profit, global organisation for business, government, academic and other professionals concerned with energy and related issues in the international community. We advance the understanding and application of economics across all aspects of energy and foster communication amongst energy concerned professionals.

We facilitate:

- Worldwide information flow and exchange of ideas on energy issues
- High quality research
- Development and education of students and energy professionals

We accomplish this through:

- Providing leading edge publications and electronic media
- Organizing international and regional conferences
- Building networks of energy concerned professionals

Editor's Note

We focus on electricity generation and transmission in this issue and will continue to do so in the coming spring issue. The subject clearly elicits a great deal of interest.

Independent regulation has long been considered an essential element in creating the environment for the mobilization of private sector investment in infrastructure. Robert Borgström reviews that principle and offers a cautionary note about an evolutionary variant, "regulation by contract" and the adverse impact it may have upon sustainable economic development.

Tobey Winters writes that the arena of public discourse, the debate on a low carbon future has not focused on investment strategy and incentives to achieve national objectives, but rather positions taking on "good" and "bad" fuels and technologies. To those who take the International Panel of Climate Change (IPCC) warnings to heart, this article counsels: be careful of what you wish for.

Danielle Devogelaer and Dominique Gusbin discuss the influence a 15% reduction in energy related CO_2 emissions of the Belgian power generation system would have on Belgium following the 2012 initiatives. Three frameworks differing in the technologies involved are examined and their impact on power generation and related investments scrutinized.

Reinhard Haas, Christian Redl, Hans Auer analyze the evolution of and recent developments in the liberalised Western and Central European electricity markets focusing on price formation in wholesale markets. They discuss future developments with respect to market integration and security of supply.

Jørgen Bjørndalen and Torkel Bugten note that the benefits of interconnectors are important in order to decide which interconnections should be established. This article addresses how especially long term effects can be identified, and that in order to cover all potential effects in practical applications, one has to rely on several partial analyses.

Akin Iwayemi notes that poor electricity service has been a regular feature in the Nigerian economy for the past three decades. He examines the "curse of electricity", and how this can be overcome. He concludes this can be accomplished by strengthening the institutional infrastructure and governance structure so that arbitrary government intervention will be restrained and corruption minimized, along with the creation of a market based electricity system

DLW

ISTANBUL INTERNATIONAL CONFERENCE

STUDENT SCHOLARSHIPS AVAILABLE

The Istanbul conference organizers are offering a limited number of student scholarships to the 31st IAEE International Conference. Any student applying to receive scholarship funds should:

1) Submit a letter stating that you are a full-time student and are not employed full-time. The letter should briefly describe your energy interests and tell what you hope to accomplish by attending the conference. The letter should also provide the name and contact information for your main faculty supervisor or your department chair, and should include a copy of your student identification card.

2) Submit a brief letter from a faculty member, preferably your main faculty supervisor, indicating your research interests, the nature of your academic program, and your academic progress. The faculty member should state whether he or she recommends that you be awarded the scholarship funds.

Student scholarship support will be used to cover the conference registration fees for a limited number of students to attend the IAEE International conference. All travel (air/ground) and hotel accommodations, meal costs (in addition to conference-provided meals), etc., will be the responsibility of each individual recipient of scholarship funds.

Completed applications should be submitted to IAEE Headquarters office no later than May 20, 2008, for consideration. Please email to: David L. Williams, Executive Director, IAEE, 28790 Chagrin Blvd., Suite 350, Cleveland, OH 44122, iaee@iaee.org

Students who do not wish to apply for scholarship support may also attend the conference at reduced student registration rates. Please visit http://www.iaee08ist.org/?Page=Registration to obtain student registration rate information. Please note that IAEE and the Istanbul conference organizers reserve the right to verify student status.

If you have any further questions regarding Istanbul student scholarship program, please do not hesitate to contact David Williams, IAEE Executive Director, at 216-464-2785 or via e-mail at: iaee@iaee.org You may also contact Gurkan Kumbaroglu, Istanbul General Conference Chairman, at 90-212-359-7079 or via e-mail at: gurkank@boun.edu.tr

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IAEE Past President Shares Nobel Peace Prize

Rajendra "Patchy" Pachauri with Nobel Peace Prize on the right. Al Gore on the left.

IAEE founding member, and 1988 President, Rajendra "Patchy" Pachauri ('97), in his capacity as Chairman of the Intergovernmental Panel on Climate Change (the IPCC), shared this year's Nobel Peace prize with Former Vice President, Al Gore. The Norwegian Nobel Committee awarded the prize for their efforts to build up and disseminate greater knowledge about manmade climate change, and to lay the foundations for the measures that are needed to counteract such change.

Patchy, an Indian national, enjoys close ties with the United States. After early education in India, he joined the North Carolina State University in Raleigh, NC where he obtained a PhD in Industrial Engineering, and another in Economics. In addition to serving on North Carolina's Faculty, he has held visiting Fellowships at West Virginia University, the East West Center in Hawaii, Yale University, and the World Bank.

At home in India he has played a key role in the development of that country's energy, development and environment policies over the past 30 years. He serves on the Panel of Eminent Persons on Power, the Advisory Board on Energy, the National Environmental Council and the Economic Advisory Council, all reporting directly to the Prime Minister. He is also a Director of the Indian Oil Corporation Limited (a Fortune 500 Company). In recognition, he was awarded, in 2001, the Padma Bjushan, one of India's highest civilian awards for distinguished service to the nation.

His base in India over the past 25 years has been The Energy and Resources Institute (TERI) that he started from scratch in 1982 to do research and provide professional support in energy, environment, forestry, biotechnology and the conservation of natural resources. From its modest beginning – perhaps as modest as Patchy plus a secretary – it now has over 700 employees, drawn from a wide range of disciplines and experience, supported by world class infrastructure and facilities, and with its own recently founded University.

Though initially intended to address Indian problems of poverty and resource management, TERI has blossomed into a major global institution with offices in North America, Europe, Japan and the Gulf. Patchy's leadership at TERI earned him a much deserved international reputation. Among many appointments, he has been President of the Asian Energy Institute since 1992, and has just joined the board of the Global Humanitarian Forum founded by former United Nations Secretary General Kofi Annan. He was honored as "Officier de la Légion d'honneur" by the French government in 2006.

His reputation both at home and abroad, and the immense range of his experience, made him a natural choice to be appointed Chairman of the IPCC in 2002. The IPCC, established in 1988 by the World Meteorological Organization and the United Nations Environment Progamme, is a unique organization. Its assessments of the impacts of climate change are prepared by hundreds of authors representing a wide range of disciplines, from all regions of the world, who devote their time and labor on a voluntary basis. It has the authoritative backing of both the scientific community and governments. Under Patchy's leadership this body is recognized as the undisputed authority in the analysis of the causes and impacts of climate change. His ability to communicate its complex results ensures that its findings are heeded throughout the world.

Patchy is a man of many talents. In addition to authoring more than 20 books and countless articles on professional subjects, he has published a book of English verse. He is also an ardent cricketer, playing regularly for the TERI team in the Delhi Corporate cricket league. Though he plays some golf, he once remarked that he prefers cricket, as he would rather run after a ball than walk up to it and hit it again and again -- a sentiment that this writer, a tennis player, heartily endorses.

It is a great honor for the IAEE to have one of its own receive this most prestigious award. We all join in congratulating Patchy, and conveying our appreciation for all that he has done for the IAEE over the years.

Joy Dunkerly

Einar Hope Knighted

Einar Hope, long-time IAEE member and officer, was awarded the Knight of the 1st Class of the Royal Norwegian Order of St. Olav for his "services to country and mankind."

In presenting the honor on behalf of the King of Norway, County Prefect, Sevein Alsaker, noted that, "Hope has made important and valuable contributions to applied economic research that has had a strong influence on policy formation." He went on to note that Hope headed the research that led to the design of an operational market-based system for the Norwegian electricity market which in turn laid the foundation for the Norwegian Energy Act.

Hope was associated with the Norwegian School of Economics and Business Administration in various capacities for a number of years, first as the Director of the Institute of Industrial Economics, then as Executive Director of the Centre for Applied Research and later as Executive Director of the Foundation for Research in Economics and Business Administration.

In 1995 he was appointed Director General of the Norwegian Competition Authority in the Norwegian Ministry of Finance, a post he held until 1999. Under his leadership the Authority became a "..modern and well administered" organization, said Alsaker.

Several of his peers, speaking at the award ceremony, noted Einar's professional approach and commitment to applied research as well as his outstanding leadership capability that included both kindness and patience.

Einar Hope addressing the assembly following the award of Knight of the 1st Class of the Royal Norwegian Order of St. Olav

Mobilizing Resources for Power Sector Development: A Cautionary Note about "Regulation by Contract"

By Robert Eric Borgström*

Overview

Independent regulation has long been considered an essential element in creating the environment for the mobilization of private sector investment. Nonetheless, and despite the optimism with which this concept was promoted throughout the 1990's with respect to the developing and transitional economies, potential investors have often been disappointed by the slow pace of reform. The uncertainties of dealing with fledgling regulators and the interventions of governments to keep tariffs at politically acceptable, but less than cost-reflective levels, have conflicted with a rapidly growing demand for electricity and the need to raise capital for infrastructure projects. As a result, some propose that the classical regulatory framework be restructured to incorporate "Regulation by Contract" with the objective of mobilizing resources over the near term. This paper reviews the objectives of independent regulation as well as the pragmatism of regulatory contracts and cautions about the risks to sustainable economic development that may derive from the latter.

Projected Energy Demand and Investment Requirements

The U.S. Department of Energy's Energy Information Administration (DOE/EIA) projects that by 2030, the worldwide demand for electricity will be 30,364 billion kilowatt hours (BKwh); this is an average annual growth rate of 2.4 per cent.[1] To meet this growth in demand, it is expected that generating capacity will need to increase by 61 per cent from 3,741 Gigawatts (GW) in 2004 to 6,014 GW by 2030. This is an average annual increase in capacity of 87 GW.[2]

Most of the growth will occur in countries outside of the Organization for Economic Cooperation and Development (OECD). Non-OECD countries are expected to require an additional 1,695 GW of generation capacity over the period 2004-2030, an average annual increase in capacity of 65 GW. This incremental capacity is equal to 110 per cent of the installed capacity in non-OECD countries in 2004 and approximately the equivalent of the installed capacity in the United States and OECD-Europe in that year.[3]

In 2003 the OECD/International Energy Agency (IEA) conducted a comprehensive review of worldwide energy investment requirements. That review estimated that an investment of roughly $9.8 Trillion (in 2000 dollars) would be required over the years 2001-2030 to develop a power sector infrastructure capable of meeting the worldwide growth in demand for electricity that is anticipated over that period. ($4.1 Trillion and $.4 Trillion will be required for new and refurbished generation, respectively; $1.6 Trillion will be required to extend transmission grids by 3.7 million kilometers; and $3.8 Trillion will be required for distribution networks.)[4]

Of the expected total investment, $5.1 Trillion (51.9%) is expected to be made in developing countries. ($2.2 Trillion for generation; $.9 Trillion for transmission; and $2.0 Trillion for distribution.) This is an average annual investment of $170 Billion.[5] According to Fatih Birol, IEA's Chief Economist,

> Mobilizing the capital to build new power stations and add sufficient transmission and distribution capacity may prove an insurmountable challenge for some developing countries. The risk of underinvestment is perhaps greatest in many African countries and India.[6]

Clearly these countries will need to look beyond their national wherewithal to the private sector for the required investment.

Mobilizing Investments for Power Sector Infrastructure Development

Prior to the 1990's, investment in the power sector infrastructures of developing and transitional economies was typically the role of the state. Following the collapse of the command economies, competing demands for sharply lowered tax revenues required a broad reorientation of investment strategies to include private sector participation. These states quickly learned that just proposing the societal benefits to be derived from infrastructure development was insufficient in raising capital from the private sector. Not only must the state compete for credits and grants with the investment opportunities proposed by other states, the prospective lenders and grantors

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See footnotes at end of text.

demanded structural reforms to help mitigate the risks of investing in an economy that was in the early stages of market-reorientation. Included in those required structural reforms were:

(1) The creation of a legal structure that respects the rights of the private sector
(2) The corporatization of the enterprise (e.g., the state electric company) into a business unit (e.g., the national electric company, a joint-stock company) with the presumption that it would not be run by the state's political leadership;
(3) The commercialization of that business unit with the idea that it would become market-oriented, charging and collecting tariffs that fully recovered costs of production as well as a reasonable return on investment; and
(4) The establishment of a regulatory authority that would act as a proxy for competition over natural monopolies and ensure, on behalf of stakeholders, that there would be transparency and stakeholder participation in economic decision-making.

In 1993, The World Bank's seminal policy paper on institutional, regulatory and financial reform made it clear that:

> "*A requirement for all power lending* [by The World Bank] *will be an explicit country movement toward the establishment of a legal framework and regulatory processes satisfactory to the Bank. To this end, in conjunction with other economy-wide initiatives, the Bank will require countries to set up transparent regulatory processes that are clearly independent of power suppliers and that avoid government interference in day-to-day power company operations (regardless of whether the company is privately or publicly owned). …"* [emphasis in the original] [7]

Independent Regulation

The independent regulator model derives from English Common Law. The regulator, acting in the public interest, is given considerable discretion to take decisions on tariffs and service issues within a framework of laws and regulations. These decisions are made transparently and with full accountability. Public proceedings are an integral part of this process and stakeholders are pro-actively given opportunities to present their views to the regulator for consideration before the decision is taken. Within this framework, an affected party's avenue of appeal is through the court, but only with respect to procedure. The regulator's substantive decision, insofar as it was reached by accordance with lawfully established procedures, is not subject to further review. Moreover, it is the internationally regarded best practice that regulators, although they are appointees (usually of the president) may not be removed from office during their tenure except for legal cause.

Although many developing and transitional economies adopted this framework (or leaned heavily in that direction), the functionality of many recently created regulators is still a work in progress. Whereas the objective was to establish a truly separate and autonomous organization of government that exercises independent regulatory discretion, many so-called regulators are either:

(a) "separate regulators" – a functionally separate organization is established within a ministry that acts with quasi-independence but whose "decisions" are either recommendations to the minister, who has the "final" decision, or decisions that are subject to *de facto* ministerial review (e.g., allowing the regulator's independent tariff decision to be published in an official gazette).[8] Or,
(b) "embedded regulators" – one or more functions (e.g., offices, departments, "desks", etc.) that are set up within a ministry or ministries and perform regulatory duties subject to the review and coordination of higher governmental authorities.

In either of these cases, regulatory decisions are ultimately left to the discretion of a politician who may take or review decisions with a view to achieving purely political objectives.[9] This regulatory risk ("regulatory capture") – i.e., the degree to which the regulator is actually given "independence" to take regulatory decisions – is a significant issue for potential investors.[10]

In 2003, The World Bank revisited the effectiveness of the independent regulator model:

> With the benefit of close to 10 years of experience [since The World Bank's policy paper in 1993], we find that *the expected benefit of independent regulatory commissions following general tariff principles – a commercially viable power sector that benefits both consumers and investors – has not been realized.* [Emphasis in the original.] The basic problem seems to be a "weak governance environment". This, in turn, has meant that new commissions have often failed to achieve independent and technical decision-making. Although new regulatory insti-

> tutions have been created, it appears that in some countries "institutional change … changed nothing" or at the least very little. …[11]

Accurate as this statement is, the view it represents is somewhat impatient. Ten years of experience is a short time-line for the building of regulatory credibility. One should view The World Bank's 1993 policy paper as the starting point of a generational process. The regulatory framework it outlined will not quickly replicate the commercial successes that regulators operating under more mature, free market conditions have achieved after lengthy experience. [12]

Nonetheless, Bakovic et. al. are correct that the problem of resource mobilization remains to be addressed. Over the period 1990-2006 private sector investment in the power sectors of developing countries totaled $267 Billion, an average annual investment of only $15.7 Billion.[13] This amount is only 9.2% of the annual investment required by the 2003 IEA projection (cited above).[14]

The remedy proposed by Bakovic et. al. in 2003[15], and then reiterated by Brown et. al. in the World Bank's 2006 "Handbook for the Evaluation for Evaluating Infrastructure Regulatory Systems"[16] is a regulatory model incorporating "Regulation by Contract".

Regulation by Contract

Regulation by Contract refers generally to "regulating" the relationship between governments and investors/service providers through the vehicle of bi-lateral agreements, such as a license or a concession contract. The agreements may be either stand-alone documents or negotiated terms embedded within a suite of privatization agreements, secondary regulations, decrees or even the power sector reform law itself.[17] Typically the agreements include detailed provisions for a return on and of investment, specifications with respect to quality of service, tariffs and a mechanism for their adjustment over time or in consideration of other exogenous variables affecting the service provider's cost of service (e.g., inflation). These contracts may be subject to administration by the country's regulatory authority (if one exists; many such contracts precede the functionalization of a regulator), but enforcement is left to the country's legal system. The operative effect is that the regulator may have a monitoring function with respect to the contract's implementation, but its regulatory discretion, if not altogether precluded, is greatly restricted.

The issues being addressed by this restriction are those of regulatory capacity and commitment.[18] Of what comfort to a potential investor is the prospect of being subject to the decisions of a newly established regulator who is wrestling with organizational start-up issues such as (a) insufficient staff; (b) untrained staff; and (c) inadequate secondary legislation (rules, regulations and procedures)? Lacking a regulatory "track record" by which the risk of an investment can be estimated, how confident can the potential investor be that the revenue assumptions underlying the proposed investment will remain in effect throughout the project. What guarantee is there that the regulator will not implement a new set of rules each time there is an application for tariff adjustment?

These "teething" issues are impediments to the mobilization of resources although these issues should and can become less significant over time *if* – but *only if* – it is the will of the government to develop its regulatory capacity to internationally acceptable standards of policy and performance. As Eberhard notes:

> Investors, operators and consumers will benefit from regulatory governance systems that match regulatory discretion with levels of regulatory commitment and institutional endowment. Regulatory performance can also be improved through mandatory, independent reviews of regulators; building the demand side for regulatory performance; and through sustained regulatory capacity building initiatives …[19]

Owing to the urgency of mobilizing resources, there is validity in adopting the hybrid approach of combining regulatory independence with a clearly specified regulatory contract that is negotiated by (and, therefore, has the buy in of) political authorities. A bi-lateral contract of this kind is certainly likely to be signed with comparative ease relative to a lengthy regulatory process (particularly with a start-up regulatory regime). However, this should be viewed as an interim measure *while independent regulatory capacity and credibility is being developed.*

Bakovic, et. al., disagree. They argue that:

> in many developed countries, multi-year price or revenue caps, *which are a form of regulation by contract,* have become the system of choice in setting retail tariffs both for new regulatory commissions, such as exist in England and Wales and the Netherlands, and old regulatory commissions, such as exist in the United States. … In effect, they have decided to give up regulatory

> discretion because they expect that they will get more efficient performance from the regulated entity if they commit to a multi-year tariff regime. … This suggests that a performance-based, multi-year tariff-setting system, the key component of the regulatory contract, should be the preferred approach for regulating private distribution entities and developed countries and *not just for a transition period.* [emphases added].[20]

It may be too early to judge whether the "Regulation by Contract" approach has been successful in mobilizing resources; over the period 2004-6, private sector concession contract investments in the power sector of developing countries have totaled only $347 Million per year.[21] Nonetheless there is risk to the sustainability of overall economic reform if implementation of the bi-lateral contract does not evolve to allow a maturation of the regulator so that it can exercise independent discretion on behalf of all stakeholders.

In this respect the case of the Jakarta Water Supply Regulatory Body (JWSRB) is instructive. Water service for the city of Jakarta, Indonesia, and its environs is a responsibility of the regional government. The operation of the system is undertaken by two non-Indonesian companies under the terms of 25-year concession contracts initially signed in 1998. JWSRB was established by decree of the Governor of Jakarta in 2001, but that decree did little to affect regulatory oversight of the extant concession contracts. The troubled history of ongoing disputes between the nominal regulator and operators over regulatory jurisdiction, tariffs and quality of services held in suspense is detailed in two interesting papers, one by Achmad Lanti, Chairman of JWSRB,[22] and the other by Peter A. Bradford, former Chairman of the New York State Public Service Commission, who conducted a study of JWSRB for the Dutch Trust Fund.[23]

Reflecting on his study and on regulatory contracts in general, Bradford comments:

> Because the contract terms cannot be changed without the consent of the parties to it, regulation in this framework offers a high degree of assurance to investors. However, *it does not provide the type of consumer protection normally associated with regulatory systems that are based in statutes.* When a regulatory body takes its powers strictly from a contract, these public involvement and public protection functions, which are necessary when the government creates a privately owned or privately operated monopoly service provider, are often left to a ministry or even to a legislative body.[24] [emphasis added]

Conclusion

The principle of keeping market prices and the conditions of market entry free from unilateral control (either political, or the influence of any stakeholder group) should not in dispute. It forms the precondition for developing a free market economy that is the best, sustainable environment for the attraction of private sector investment. The independent regulatory framework embraces this principle.

Regulation by Contract address critical resource mobilization issues and, from the perspectives of investors and strategic planners, may do so more efficiently than the classical regulatory model. However, since these contracts are specifically designed to minimize regulatory discretion, they are effectively designed to preclude the essential, ongoing involvement of all stakeholders in economic decision-making that is at the heart of regulatory development and free-market economic reform. Moreover, there is a basic inequity in requiring customers of natural monopolies to accept contractual arrangements in which they have had no voice.

Extant regulatory contracts should remain in effect as negotiated; novation would adversely affect the government's credibility and credit-worthiness. However, all future contracts between the government and service providers / operators / investors should encompass the view that independent regulation ensuring transparency and stakeholder participation is the long-term objective.

Footnotes

[1] DOE/IEA, *International Energy Outlook 2007*, p. 61.

[2] *Ibid.* Table H1 at p. 201.

[3] *Ibid.*

[4] OECD/IEA, *World Energy Investment Outlook 2003*, p. 434

[5] *Ibid.* p. 448.

[6] Birol, Fatih. "Power to the People: The World Outlook for Electricity Investment". International Atomic Energy Bulletin 46.1 (2003).

[7] The World Bank. "The World Bank's Role in the Electric Power Sector: Policies for Effective Institutional, Regulatory and Financial Reform." Policy Paper, 1993, p. 14.

[8] It must be noted that some "separate regulators" are given considerable regulatory freedom to act independently. The Tanzanian Energy and Water Utilities Regulatory Authority (EWURA), is a "separate" but functionally independent regulator that reports, administratively, to the Minister of Water. The enabling legislation – the EWURA Act of 2001, at Section 7(4) – specifically precludes the Minister's intervention in the substance of a regulatory decision by providing that "… the Minister may, from time to time …, give to the [regulator] directions of a specific or general character, on specific issues" but those directions may not be "*in relation to the discharge of regulatory functions* …"[emphasis added]

[9] A typical example is the government that is unwilling to be responsible for the increase in retail electricity rates (a transparent cost to the customer) even though any shortfall in revenue to the state-owned electricity company will likely require an increase in the subsidy to be provided by the national budget (a more opaque utilization of tax revenues).

[10] See, for example: Lamech, Ranjit and Kazim Saeed, *What International Investors look for when investing in Developing Countries.* The World Bank Group: Energy and Mining Sector Board Discussion Paper No. 6 (May 2003); also: *Study on Investment and Private Sector Participation in Power Distribution in Latin America and the Caribbean Region.* Energy Sector Management Assistance Programme (ESMAP) Technical Paper 089. (Dec. 2005), p.45.

[11] Bakovic, Tonci; Bernard Tenenbaum and Fiona Woolf. "Regulation by Contract: A New Way to Privatize Electricity Distribution," World Bank Energy and Mining Sector Board Discussion Paper No. 7, May 2003, p. 14.

[12] For example, the U.S. Federal Energy Regulatory Commission (FERC) was established in 1977, succeeding the Federal Power Commission (FPC) that was established in 1920.

[13] The World Bank Private Participation in Infrastructure (PPI) Project Database. http://ppi.worldbank.org

[14] OECD/IEA, *World Energy Investment Outlook 2003*, p. 448.

[15] See Bakovic, et. al., *Op. Cit.*

[16] See Brown, Ashley C., Jon Stern and Bernard Tenenbaum, *Handbook for Evaluating Infrastructure Regulatory Systems*, The World Bank, 2006,

[17] Bakovic, et. al., p. 18.

[18] See Eberhard, Anton. *Infrastructure Regulation in Developing Countries: An Exploration of Hybrid and Transitional Models.* Public-Private Infrastructure Advisory Facility Working Paper 4 (2007); also: Lamech, Ranjit and Saeed, Kazim. *Op. cit.*

[19] Eberhard, p. 26.

[20] Backovic, et. al., pp. 20-21.

[21] The World Bank Private Participation in Infrastructure (PPI) Project Database.

[22] See Lanti, Achmad. "A Regulatory Approach to the Jakarta Water Supply Concession Contracts," in *Water Management for Large Cities,* edited by Cecilia Tortajada, et. al. (London: Routledge. 2006).

[23] See Bradford, Peter A. "Capacity Building – Jakarta Water Supply Regulatory Body: Review of Functions and Operations," Dutch Trust Fund, February 2006.

[24] Bradford, p. 4.

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Should the U.S. Coal Option be Preserved?

By Tobey Winters*

New electric generation projects fueled by coal are being turned down on the basis that new coal projects produce unacceptable amounts of CO_2 emissions. There is no national policy on CO_2 emissions, so the States are taking a piecemeal approach to regulation. To a large extent the pattern is reminiscent of the last 40 years of battles over air pollution and coal. However, this time around the issue is not about a local fix to a local, interstate or regional air pollution problem, but the absence of a national policy to address a global problem.

The regulatory framework for U.S. environmental policy since the Clean Air Act of 1970 has divided the world into approximately two groups of polluters: 1) new energy projects that must pass through the eye of the needle of local acceptance, stringent regulations and "best available" and "lowest achievable" emission technology and 2) existing plants that are largely grandfathered from change, unless science can demonstrate direct health effects. This is a bit of an exaggeration, but existing plants are a protected class when it comes to environmental performance. As applied to CO_2 emissions, the bar to new plants is beginning to be raised to the level of an effective ban on new coal plant construction. A few recent examples are cited.

Any power project in California or Washington will now need to meet a CO_2 emissions limit of 1100 lbs (499 kg) per megawatt hour, which effectively bans a conventional coal based power plant using advanced technology. In the State of Washington, a coal gasification project to produce electricity (IGCC) was denied, because it did not have a sequestration plan. In Florida, 4,400 megawatts of coal fired plants including the Southern Company's IGCC clean coal project have been rejected since the new Governor has taken office and expressed concerns about global warming and using coal. The Kansas Department of Health and Environment turned down permits for two 700 MW coal fired units to be built by a local electric cooperative citing CO_2 emissions as the basis the decision. Although CO_2 is a greenhouse gas and not a pollutant with direct health effects, the Kansas regulator reasoned that because the Supreme Court ruled that EPA could regulate in this area, the permit could be rejected on the basis that CO_2 emissions contribute to climate change. In Maine, the Town of Wiscasset voted against taking the next step in the regulatory process for a gasification project by a vote of 55% to 45%. Public concerns about the generation of CO_2 played a large role in the debate over the project.

The CO_2 issue provides the environmental movement a very powerful tool to press opposition to new coal fired power plants. The environmental community has considerable leverage over new plant decisions, but in the arena where this leverage really counts – existing coal plants, environmental interests only prevailed in a modest way after decades of legal battles that often ended at the Supreme Court. Much of the painful history of environmental regulation might have been avoided if the emission standard when plants were originally approved expired after 30 to 40 years of operation. Instead, the useful life of a coal plant has often extended to 60 years based on low cost. With their legal rights secured, plant owners fought change and plant retirement in the name of the ratepayer.

But the question is, would a ban on new coal generation make U.S. CO_2 reduction goals easier or harder to achieve? And can the U.S. make headway on CO_2 reduction without addressing the emissions from the existing coal fleet?

Basis for the Climate Change Crisis

The International Panel on Climate Change (IPCC) lacks doubt about the science, consequences, and predictability of climate change. Critics of the science, its predictability, timing and consequences are dismissed by the weight of "scientific consensus". The call for quick and dramatic action is directed to political leaders around the world and the U.S most specifically. In the face of such certainty about the future backed by the scientific establishment, political leaders can be led into policy prescriptions with huge unintended consequences. One example would be a ban on new coal fired electric generation. It is a measure that can be conceived as a vote getter in the short term, and does not appear to the man in the street as an altogether unreasonable thing to do.

The generally agreed goal as defined by the IPCC is to stabilize CO_2 concentrations at the global level at 450 parts per million (ppm). The current level is 379 ppm. Based on climate modeling, this 450 ppm goal could confine the rise of global temperature to 2.1 degrees centigrade (within a projected range from 1.4° to 3.1°). If this goal is unattainable, a more achievable goal may be closer to

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See footnotes at end of text.

550 ppm, which puts the projected temperature rise at 2.9 degrees rather than 2.1°[1]. However, this higher level raises the specter of "dangerous" climate change and "climate shocks" based on projections from models that estimate feedback effects from other models of climate effect interactions.

It is unclear how far down the chain of global warming reasoning this scientific consensus holds together, given the uncertainties and predictions about the future based on models. However, the principle that the negative impact of CO_2 emissions is due to its cumulative effect, means that any delay in CO_2 reduction today will require more reductions in the future in order to stabilize the concentration at a more future date. Because uncertainty is present, sooner action means less environmental risk. Small achievable actions that can be taken today may be as important as less certain, but potentially larger technological gains achievable in the future.

In the 2001 IPCC report, the authors concluded that in order to stabilize concentration at 450 ppm, global manmade emissions would have to drop below 1990 levels in a few decades. In order to stabilize concentration at 550 ppm, emissions need to drop below 1990 levels in about a century[2]. A recent UN Development Report states benchmarks that are much more difficult to meet than the 2001 conclusions. Based on the 2007 IPCC Report, the UN now states concentration at 450 ppm requires that global CO_2 emissions be reduced by 50% below 1990 levels by 2050. The UN Development Program reasons that developed countries like the U.S. (which has a carbon profile of 19.8 tons per capita) should be doing more to reduce emissions than developing countries like China (which has a carbon footprint of 3.8 tons per capita). The IPCC argues that the developed countries' objective should be 80% CO_2 emissions reduction by 2050 in order to achieve the overall goal[3]. These benchmarks were set out just before the Conference in Bali, Indonesia on what to do when the Kyoto accord expires in 2012. In a largely symbolic act on the first day of the Conference, the new Prime Minister of Australia announced that Australia would sign the Kyoto accord, leaving the U.S. as the only major developed nation that has not joined.

The political pressure mounts as U.S. presidential elections near. But the question is posed: Is an 80% reduction in CO_2 emissions achievable in the U.S. electric sector? Would a ban on new coal fired power plants help or hinder that objective? What is the role of existing coal plants?

New Plant Electric Generation Options

To meet a forecasted growth of electricity of 1.3% per year to 2030, EIA projects 228 gigawatts of new generation will be needed[4]. Renewable projects and nuclear plants could meet the demand with natural gas as a back-stop to match demand and supply. Only wind energy can deliver renewable energy at large scale. Wind projects have averaged about 3 gigawatts of new generation per year over the past 3 years. Assuming that wind generation could double its contribution to 6 gigawatts per year, an additional 138 gigawatts could come from wind. However, wind availability and electric transmission constraints limits actual generation. EIA generously computes wind turbine resource utilization at 33%. This rate is about half or less of what a new natural gas combined cycle units typically achieve based on the cost of generation. By contrast, a new coal or nuclear unit would aim at 80 to 90% utilization. Therefore, additional capacity would be needed beyond 228 Megawatts to fill in during times when wind resources are not available.

If the nuclear industry could have 3 suppliers each with a new commercial 1000 Megawatt unit placed in service by 2017, and each supplier could average a new unit a year from 2018 to 2030, the nuclear industry could add another 69 GW of power to the grid. After years of not building nuclear plants, both the industry base and regulatory process will take some time to develop the capacity to approve, build and operate these plants on time. The gap between demand and supply growth could be made up by fast start natural gas capacity to back-stop the undersupply of generation. Some variation of this illustration could stop the growth of CO_2 emissions in the electric sector to near zero, but it would not reduce total emissions. And it would not begin to get reductions near 80%.

Path to Emission Reductions

In order to reduce total emissions, the existing coal fleet needs to be replaced. The average age of a coal fired plant in the U.S. weighted by size is about 30 years old. This means that in the next 30 years, most of the fleet should be retired. Regardless of size, more coal units now in service were built in the 1950s than were built in any subsequent decade, which means that a number of units could be retired today, if a cost effective alternative were available. Over the next 40 years, the entire coal fleet could be replaced.

The least cost way to replace most of the existing coal fleet is with new coal technology. As noted in table 1 below, there is a huge gap between the CO_2 profile of new coal new technology and the existing fleet. New technologies significantly reduce CO_2 emissions even before the application of carbon capture and storage technologies. Co-firing of biomass with coal may also be environmentally and economically preferable to using biomass for ethanol production for the consumer and the biomass supplier[5]. Based on the logic that biomass is a net zero contributor to man-made emissions, co-firing with biomass reduces CO_2 beyond reductions noted in table 1.

Before the application of carbon capture and storage and without co-firing of biomass, new coal units can reduce coal fleet emissions by 24% to 57%. The benchmark established by California and adopted by the State of Washington implies a 51% reduction relative to existing coal units. A new natural gas combined cycle plant ideally achieves 61% reduction, but due to the frequent starts and stops and weather conditions when natural gas units are used, actual reduction is less in practice.

Stack Emissions of CO_2 (kilograms per megawatt hour)					
Existing Coal[1]	**New USPC[2]**	**New IGCC[3]**	**Co-Pro[4]**	**Standard[5]**	**New CC[6]**
1016.3	770.7	736.5	433.9 to 633.3	498.9	393.7
100%	-24.2%	-27.5%	-57.3 to -37.7%	-50.9%	-61.3%
[1]weighted avg. of all U.S. coal units (2004) over 100 MW	[2]Ultra super crtical pulverized coal	[3]Integrated gasification combined cycle coal	[4]Co-production of electricity and F-T diesel fuel using coal	[5]Standard adopted by California and Washington	[6]Natural gas combined cycle
"USPC "and "IGCC" based on Nexant analysis of environmental foot print : EPA Report 430/R-06/006. Co-production based on a project specific carbon balance.					

USPC "and "IGCC" based on Nexant analysis of environmental foot print : EPA Report 430/R-06/006. Co-production based on a project specific carbon balance.

Table 1 CO_2 Emission Profiles of Fossil Technologies

The co-production technology (noted in table 1 column 4) shows two estimates of reduction. The lower number represents CO_2 emissions based on equivalent electric energy, where the useful energy in the liquid fuel production is added to the electric production to compute the overall emissions rate. By comparison, the higher number in column 4 simply scales the co-production plant to an IGCC project based on overall plant energy efficiency[6].

Co-production also has one other unique feature compared to IGCC and PC coal. In order to make the F-T diesel fuel, the CO_2 in the synthesis gas produced from coal must be captured. This fraction of the overall CO_2 emissions is about 25% of total stack emissions. With co-production, once the investment in the plant is made, the incremental cost of adding the carbon storage is lower than for the other coal options.

The U.S. could start down the path of emission reduction by re-investing in a new coal fleet and achieve reductions of 25-50% with new technology and biomass co-firing, with carbon storage options added later when commercially viable. If urgency of action is important, then it follows that it is foolish to stop new construction of coal technology now, on the theory that new coal is unacceptable until carbon sequestration is in place.

New coal fired generation is part of the solution to CO_2 stabilization. In addition, there are air pollution reduction benefits of modernizing the existing coal fleet, as shown in table 2.

The electric power industry is continuing to invest in NOx controls and SO_2 scrubbers to reduce emissions from old existing units to meet EPA and State regulations. These less efficient coal units are getting investment that would not occur if there were incentives to invest in new plants instead. By analogy, few consumers would invest 20% of the cost of new car to fix their 10 year old vehicle. The incentive to run old plants should be reversed to an incentive to build new plants, and retire the old plants. One side effect of air pollution controls on old plants is the reduction in overall plant efficiency, which increases (modestly to be sure) the CO_2 emissions per megawatt hour produced.

	Air Pollutant Comparisons - Coal Based			
Air Pollutant	**Existing Coal[1]**	**New USPC[2]**	**New IGCC[3]**	**Co-Pro[4]**
NOx (kg per Mwhr)	1.7	0.2	0.16	0.04
SO2 (kg per Mwhr)	4.7	0.29	0.15	0.06
Mercury (grams per Gwhr)	23.6	1.8	1.8	1.8
	[1]weighted avg. of all U.S. coal units (2004) over 100 MW equivalent	[2]Ultra super critical pulverized coal	[3]Integrated gasification combined cycle coal	[4] Electricity and F-T diesel fuel

USPC and IGCC based on Nexant analysis of environmental foot print : EPA Report 430/R-06/006. Mercury reductions based on average bituminous coal mercury content and a 66% removal rate. Co-production based on project specific heat and mass balance.

Table 2: Pollutant Emissions of New vs. Existing Plants

Fleet modernization provides three benefits: lower pollution, an additional path to CO_2 reduction and a less expensive option to new generation investment. If global warming requires urgent action to stabilize CO_2 concentration at 450 ppm, then the U.S. should be building, not rejecting new coal plants and providing incentives for the most efficient technologies. To insist that new coal investment should wait until carbon capture and storage is proven only delays action. Investors come in after new technologies demonstrate a period of successful operation at competitive prices. CO_2 reduction now does not preclude more reduction later.

If the 450 ppm goal is unattainable, and 550 ppm CO_2 concentration is the real objective, then we have a few decades to chase a silver bullet technology solution, like the hydrogen economy. If urgency is important and/or the silver bullet does not exist, then a ban on new coal works against early CO_2 stabilization. The anti-coal instinct based on once bitten, twice shy, while understandable, is counterproductive.

The premise of this argument is that any path to a low carbon future requires capital investment, raises energy prices and involves financial risk. Our preferences and biases for where that capital investment should be made (energy efficiency to reduce demand, renewable technologies, nuclear power or modernization of the coal fleet) should not preclude using all the means required to accomplish the objective. Greater urgency requires less prescription about how to obtain the CO_2 reduction goal.

New coal technology can modernize the existing coal fleet, and provide benefits that can also be justified on economic and air pollution grounds. So, there is also something here for global warming skeptics too.

Footnotes

[1] IPCC, Climate Change 2007, The Physical Science Basis, p. 791.

[2] 2001 IPCC Technical Summary of the Working Group 1 report, page 75.

[3] UN Human Development Report 2007/8, "Fighting Climate Change".

[4] From 1995 to 2006 electricity consumption increased 1.8% per year, so EIA projections imply some demand reduction or reduced energy intensiveness. Higher electricity prices could reduce growth further, thus making the new capacity targets more likely to be achieved.

[5] Eric D. Larson, Low GHG Liquid Fuels from Coal and Biomass, Presentation to Chewonki Carbon Capture and Storage Seminar, Wiscasset, ME, October 24, 2007. Eric D. Larson, A Review of Life-Cycle Analysis Studies on Liquid Biofuels Systems for the Transport Sector, Princeton Environmental Institute, Princeton University, Energy for Sustainable Development, Vol 10, No. 2, June 2006.

[6] With co-production the emissions from the stack are always the same, but the production of liquid fuels and electricity varies with demand and price. Using the co-generator convention, the megawatt hour useful energy of the liquid fuel equivalent is calculated at 3413 Btus per kWhr. Because the stack emissions are constant regardless of the proportion of electricity to liquid fuels produced, this method computes a constant emissions rate. The counter argument is that the liquid fuels from co-production might otherwise come from a more efficient refinery using oil rather than coal as a feedstock. However, the argument ignores several realities: refineries make a whole slate of products and the efficiency of the overall plant depends on producing the complete slate of products – not just the premium product. Second, the marginal barrel of oil as a comparison point is unknown. The oil might be coming from oil sands, whose CO_2 emissions overall may be higher. Third, in this calculation the CO_2 emission rate varies through time depending on product mix; the latter method compares a known to a hypothetical.

How Could GHG Reduction Targets Beyond 2012 Influence Investments in Electricity Generation in Belgium

By Danielle Devogelaer and Dominique Gusbin*

Abstract

This article discusses the influence a specific (determined ex ante) target to reduce energy related CO_2 emissions in the period after 2012 initiates on the Belgian power generation system. In a first step, a baseline is defined in which current policy and ongoing trends and structural changes are supposed to continue. Over the period 2000-2030, the average electricity and steam production cost rise 36% and sector specific investments between 2006 and 2030 amount up to € 17 billion (expressed in €2000), covering the replacement of obsolete plants and the additional capacity needed to cope with surging demand (on average +1.0% per annum). In terms of energy CO_2, the most dominant greenhouse gas, the baseline foresees a growth by 32% compared to 1990, the base year of the Kyoto Protocol. In order to combat climate change, the energy scene depicted in the baseline is obviously not sustainable. The article then changes scope and sets a -15% target in comparison with 1990 on energy CO_2 emissions on Belgian soil to be reached by the year 2030. In order to accomplish this goal, three energy policy frameworks are examined. These frameworks are in fact different combinations of (the lack of) two energy technologies, namely nuclear power plants and carbon capture and storage (CCS). The impact of this -15% objective on the production of electricity and steam and more specifically on investments in the sector is scrutinized.

Introduction

The results presented in this article are based on quantitative analyses realised with the aid of the model PRIMES (NTUA, 2007). PRIMES is a partial equilibrium model that integrates energy supply and demand on a national or European level. Since it is a partial equilibrium model solely, the energy system is modelled and not the rest of the economy. It is principally conceived to build energy projections for the long term (up to 2030), to analyse scenarios and to study the impact of policies and measures that potentially can influence the energy system. Although numerous aspects of the energy system can be analysed with PRIMES[1], this article only focuses on the Belgian electricity sector through the examination of the capacity, capacity extension, average production costs, investments and CO_2 emissions.

As a starting point, a baseline or reference scenario is run. The reference scenario that is used for this analysis is the same as the one published in May 2006 by dg tren of the European Commission (CE, 2006). In the PRIMES baseline, energy developments are simulated on the basis of assumptions concerning, e.g., economic and social development, world energy markets and implemented policies. Starting from these assumptions, developments are driven by market forces so that efficient energy solutions are chosen whenever this is economic, taking into account significant discount rates including risk premiums.

In PRIMES, the indicators on CO_2 or the share of RES are modelling results that inform the policy process about the effects of policies or their absence. This approach enables the baseline to illustrate the gap between policy ambitions and what is already underway for delivering on these policy aspirations. This approach allows the baseline to be a valid reference case for the subsequent evaluation of the effects of energy and climate policies and measures. Such measures are modelled in the policy scenarios irrespective of their state of implementation (answering "what if" questions).

The policy scenarios chosen in this study are scenarios in which an energy CO_2 emission reduction target in Belgium is fixed and the effect of different energy policy options is investigated. In PRIMES, the installation of a constraint on emissions is equivalent with the introduction of a variable that reflects the economic cost imposed by this constraint. This variable is the marginal abatement cost (also called *carbon value*) associated with this constraint; it represents the cost to reduce the last unit of emissions that needs to be eliminated in order to reach the set emission target. The marginal abatement cost can also be seen as the emission permits' price determined on a perfect market and of which the quantity corresponds to the constraint. The carbon value by hypothesis is unique for all sectors; it initiates changes in the relative prices of the different energy forms, reflecting by this the differences in the carbon content of fuels. These changes induce technological modifications/innovations and behavioural

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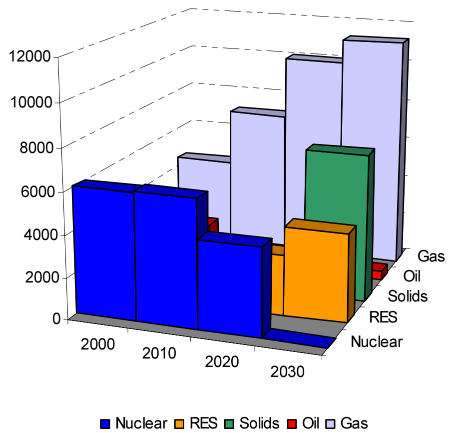
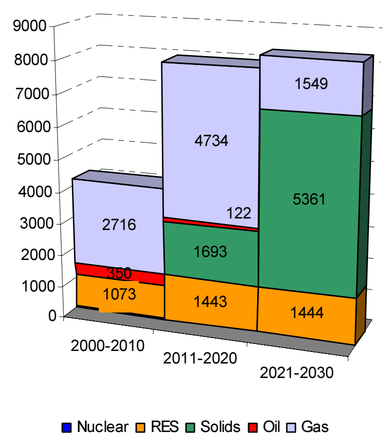


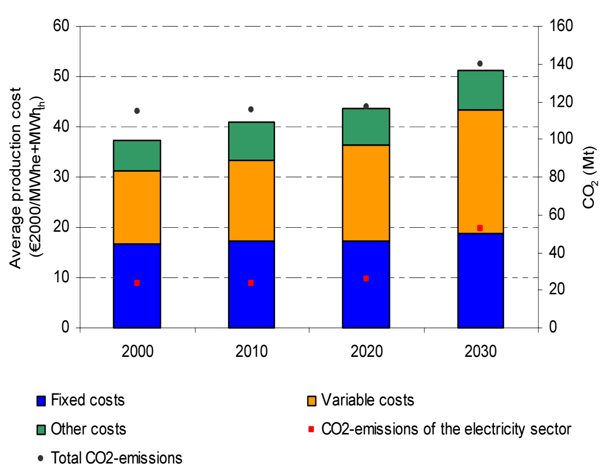
Source : PRIMES, FPB 2006b.
RES = renewable energy sources.

Figure 1
Installed Capacity for Electricity Generation, baseline (MW_e)



Source : PRIMES, FPB 2006b.
RES = renewable energy sources.

Figure 2
Electricity generation capacity expansion, baseline (MW_e)



Source : PRIMES, FPB 2006b

Figure 3 Average Power and Heat Production Cost vs. CO_2 Emissions, Evolution, baseline

adaptations of producers and consumers of energy.

Impact on the Belgian Electricity System of a CO_2 Reduction Objective

Starting from a projection of the Belgian energy system under unchanged policy (baseline), a Belgian defined objective to reduce energy CO_2 emissions in 2030 and different energy policy options, an evaluation of the impact of the realisation of this objective on the Belgian electricity sector is described.

Evolution of the Belgian Electricity System under Unchanged Policy

In order to analyse the Belgian electricity sector, a selection of indicators is chosen and subsequently discussed: the capacity (extension), the average electricity and steam production cost, investments and sectoral emissions. With the aid of graphical material, key messages are underlined.

Figure 1 shows the installed capacity allocated per energy form for the entire projection period (2000-2030). Under baseline assumptions, the nuclear installed capacity is gradually being phased out to have completely vanished by the year 2025, following the Belgian law of 2003 on the nuclear phase out[2]. The installed capacity of renewable energy sources (RES) shoots, partly because RES become competitive when fossil fuel prices increase, and partly because its intermittency dictates a strong capacity expansion in order to reach a certain production level, this level resulting from policies dedicated to the development of RES for the production of electricity. The installed capacity of solid (mainly hard coal) and gas fired plants also rises, essentially because the phased out nuclear baseload power plants have to be replaced. In 2030 the largest capacity is taken in by gas fired power plants.

Figure 2 depicts the capacity extension over the projection period: it immediately becomes clear that until 2020, mainly gas fired plants are built, whilst after 2020, the rise of supercritical coal becomes undeniable.

When it comes to the average production cost, an increase of 36% during the period 2000-2030 can be seen. This boils down to an annual growth of slightly more than 1% per year. Especially the last decade gives rise to an expansion of average production costs. This remarkable rise is due to, on the one hand, the huge investments in new power capacity in order to compensate for the deprivation of the fully amortised nuclear power capacity, and on the other hand, the strong increase in international energy prices (natural gas, coal). In 2030, the variable costs (amongst which fuel) make up more than half of the total average cost. Together with the rise in average costs, CO_2 emissions of the electricity and heat sector soar, leading to an overall increase in total CO_2 emissions.

Over the period 2006-2030, the investment expenses of the electricity sector[3] (combined heat and power included) reach approximately € 17 billion (expressed in €2000). These expenses cover at the same time the replacement of existing but obsolete plants and the additional production capacity necessary to meet the growing electricity demand.

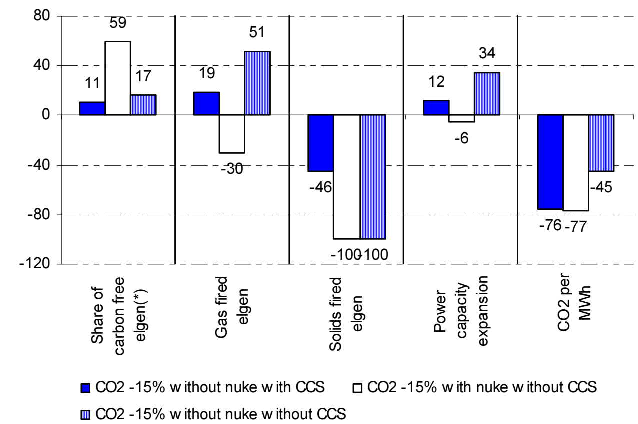
A Belgian Reduction Target in 2030

Figure 3 also showed that total CO_2 emissions in 2030 are 22% higher than in 2000 (and 32% higher than in 1990, the base year for the Kyoto Protocol). Since this is not reconcilable with the line of thinking as stated by the European Council on March 8 and 9 (20% reduction of all greenhouse gases in 2020 on a European level), we now place a constraint on the most dominant greenhouse gas, namely CO_2 emissions, and deduct its impact on the Belgian electricity system. Therefore, in what follows, it is assumed that Belgium fixes an objective to reduce its energy CO_2 emissions on its territory by 15% in 2030 compared to 1990. This choice is arbitrary in the sense that it does not result from a specific criterion to determine the Belgian share in the European burden sharing effort. Nevertheless, this objective can be imaginable if one compares it to the Belgian objective of -7,5% over the period 2008-2012[4] and if one takes into account the urge to intensify the reduction efforts at a longer time horizon. Three different energy policy orientations to reach the set objective of -15% of energy CO_2 are examined. These policy orientations are based on the (non) existence of 2 energy technologies: nuclear power plants and carbon capture and storage (CCS).

The first orientation takes into account the termination of nuclear power based electricity to conform with the calendar stipulated in the Belgian law on the nuclear phase out and assumes that CCS is not a feasible option in Belgium for the horizon 2030 (*scenario CO_2 -15% without nuke without CCS*). The second orientation also places itself in the framework of the nuclear shut down but leaves the possibility open to have CCS available in big (>300 MW) power plants burning coal or natural gas (*scenario CO_2 -15% without nuke with CCS*). Finally, the third option supposes that nuclear is allowed in Belgium for the entire period of projection, but that CCS is not available during that time horizon (*scenario CO_2 -15% with nuke without CCS*).

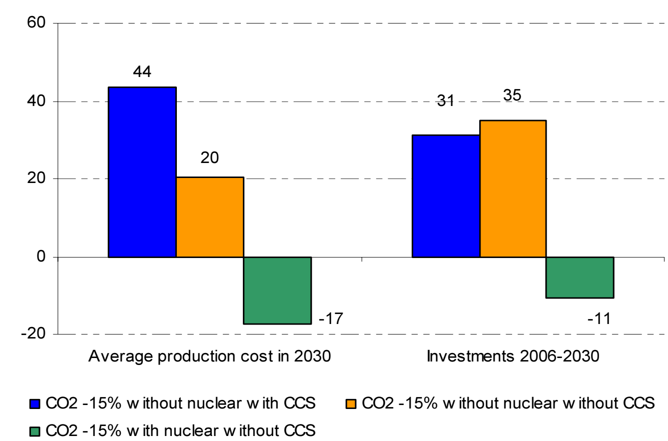
Turning to the impact this objective has on the Belgian power sector, we see a significant effect in all three scenarios. This effect results from the additional costs brought on by the carbon value (the cost of the last reduced ton of CO_2 through which the -15% reduction objective can be reached in 2030). The carbon value is a measure of the degree of ease or difficulty to fulfill the constraint and depends, amongst others, on the energy policy orientation. It is estimated to be 524 €/t CO_2 in the *CO_2 -15% without nuke without CCS* scenario, 123 €/t CO_2 in the *CO_2 -15% without nuke with CCS* scenario and 105 €/t CO_2 in the *CO_2 -15% with nuke without CCS* scenario. According to the carbon value and, underlying, the chosen policy options, the effect can vary strongly. Figure 4 illustrates this effect as a percentage (point) difference relative to the baseline.

The key messages are that the share of carbon free electricity generation is considerably higher in the *CO_2 -15% with nuke without CCS* scenario because nuclear energy is categorized as a non CO_2 emitting energy source. In the two scenarios in which CCS is not available, coal completely vanishes from the power picture because it has the highest carbon content which is severely punished by installing a carbon value. The capacity expansion in the non-nuclear scenarios is profoundly higher than in the baseline, essentially because of the strong representation of RES in these scenarios (the share of RES in power generation is 11 percentage points higher in the *CO_2 -15% without nuke with CCS* scenario and 17 percentage points higher in the *CO_2 -15% without nuke without CCS* scenario compared to the baseline). CO_2 emissions per MWh decrease considerably compared to the baseline, although the decline in the



Source : PRIMES, FPB 2006b.
(*) expressed in percentage points.

Figure 4
Some Electricity Production Related Indicators, Belgian Reduction Target for CO_2 Emissions, Year 2030, Difference with



Source : PRIMES, FPB 2006b.

Figure 5 Average Power and Heat Production Costs in 2030 and Sectoral Investments in the Period 2006-2030, Belgian Reduction Target for CO_2 Emissions, Difference with the Baseline (%)

CO_2 -15% without nuke without CCS scenario is somewhat lower because of the restricted reduction options in the power sector (this also means that reductions are relatively more important in the other sectors).

Figure 5 then summarizes the change in average production costs and investment expenses in the reduction scenarios relative to the baseline. The average production costs are depicted for the last year of the projection period, whilst the investments cover the period 2006-2030.

When a constraint is put on the energy CO_2 emissions in Belgium, the average production costs rise considerably, except when nuclear energy is part of the picture. In the non-nuclear scenarios, this cost increase can be explained by the cost of having to use specific technologies or having to switch to other fuels with lower carbon content but at a higher price.

In the scenario *CO_2 -15% without nuke without CCS,* average production costs in 2030 are 20% higher than in the baseline (64% higher than in 2000), while at the same time the power sector diminishes its CO_2 emissions by 48% relative to the baseline. The cost increase is the result of the following factors: the replacement of coal by more expensive natural gas, a larger production park in terms of installed capacity to take the intermittency of some RES into account and an electricity production level that is lower than the baseline's.

The *CO_2 -15% without nuke with CCS* scenario shows an even bigger increase in average production costs (+44% relative to the baseline, +96% relative to 2000), but on the other hand, emission reductions are also bigger than in the previous scenario (-76% in 2030 compared to the level in the baseline, against -48% in the previous scenario). This time, the costs brought about by the CCS technology are at the origin of the significant cost increase.

In the last scenario (*CO_2 -15% with nuke without CCS*), the average production costs also mount compared to 2000 (+13%), but stay below the level of the baseline and the non-nuke scenarios. Not surprisingly, this scenario can rely on the existing, fully amortised nuclear power plants to fill in large parts of its electricity generation (40%). Production costs of nuclear units are much lower than those of any new plant; this gap more than counterbalances elements that push up average costs, e.g., higher natural gas prices and extended use of intermittent RES.

Finally, between 2006 and 2030 investments in the reduction scenarios without nuclear energy are approximately one third above the level attained in the baseline. The scenario *CO_2 -15% without nuke with CCS* contains the CCS specific investments that can be considerable, in the scenario *CO_2 -15% without nuke without CCS* the RES share is significantly higher (in 2030 it reaches 45% of the installed capacity) and the total installed capacity is the highest of all scenarios (+30% compared to the baseline, +18% compared to the *CO_2 -15% without nuke with CCS* scenario and +7.5% compared to the *CO_2 -15% with nuke without CCS* in 2030). The option to keep the nuclear power plants into operation until the end of the projection period (the scenario *CO_2 -15% with nuke without CCS*) scales the investments down by 10% compared to the baseline.

Conclusion

In a nutshell, this article describes a Belgian baseline up to the year 2030 in which current policy and ongoing trends and structural changes endure, without any specific efforts or additional policies to constrain damaging greenhouse gases other than those already implemented by the end of 2004. In terms of power generation, the installed capacity will change dramatically: phase out of nuclear power plants, surge in gas fired plants, appearance of supercritical coal fired plants and a growing share of RES. Average production costs rise 36% and sector specific investments between 2006 and 2030 amount to € 17 billion.

In a second step, a CO_2 emissions constraint of -15% in 2030 relative to 1990 on Belgian soil is scrutinized for its impact on the Belgian power system. Three energy policy frameworks are examined, differing in the (lack of) utilization of two energy technologies, e.g., nuclear energy and CCS. According to the chosen energy policy, the power sector undergoes big changes (e.g., absence of coal in the non-CCS scenarios, way more gas fired plants in the non-nuke scenarios, …). Impact on average production costs and investments also depends on the adopted policy angle: compared to the baseline, costs and investments are higher when nuclear power is being phased out, lower otherwise. Investments are highest (+35% relative to the baseline) when neither energy technology is allowed.

Footnotes

[1] Interested readers are referred to Devogleaer and Gusbin (2007) and both 2006 studies of the Federal Planning Bureau for an overview on long term projections on all aspects of the Belgian energy system for a multitude of (policy) scenarios.

[2] Belgian Monitor, February 28, 2003, pp. 9879-9880.

[3] The investment expenses comprise all new CHP plants, but not the investments in transmission and distribution grids.

[4] For all greenhouse gases and compared with 1990 (1995 for the fluorinated gases).

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Mid-term Perspectives for the Western/Central European Electricity Market

By Reinhard Haas, Christian Redl and Hans Auer*

Introduction

The restructuring process of electricity markets in Europe started in the late 1990s and is still going on. This process was triggered by the Directive 96/92/EC of the European Parliament and of the Council concerning common rules for the internal market in electricity (EC, 1997).

This article will analyse the recent developments in the liberalised Western and Central European electricity markets and discuss future developments with respect to system adequacy, reliability and security of supply.

The European Electricity Market(s)

A major objective of liberalising the European electricity supply industry was and still is the creation of one common market. Yet, currently this area consists of several sub-markets separated by partly insufficient transmission capacity and differences in access conditions to the grid. Another major obstacle for a joint competitive European market is the low number of competitors resulting in a general lack of competition in virtually all local and national wholesale as well as retail electricity markets and also because barriers to entry and incentives to collude remain too high. Additionally, increasing horizontal integration with natural gas supply is observed. Hence, the paramount objective is still to construct competitive markets while – at the same time – ensuring a reasonable level of grid reliability and supply adequacy (Haas et al., 2006).

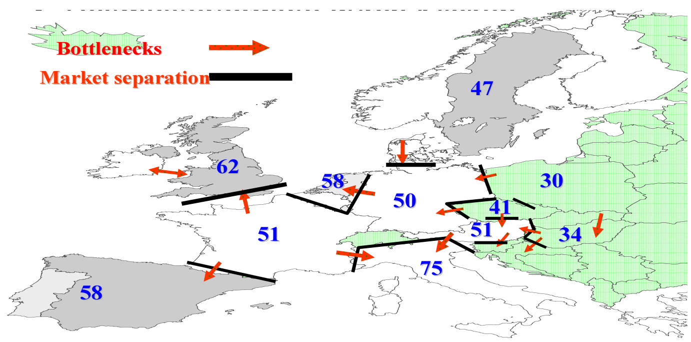

Figure 1
Average Wholesale Electricity Prices in EUR/MWh and Transmission Grid Bottlenecks in Europe in 2006.
Source: Power Exchanges

Figure 1 depicts the average wholesale prices in these different sub-markets in 2006 due to cross-border transmission bottlenecks or other exchange barriers (e.g., long-term contracts).

The most important sub-market is the Western European market comprising Austria (AT), France (FR), Germany (DE), and Switzerland (CH).[1] As these countries are not separated by permanent cross-border transmission capacity bottlenecks, electricity can be traded virtually without limitations between these countries. This, in turn, causes prices to converge due to arbitrage reasons (see Figure 2). The European Energy Exchange (EEX), located in Leipzig, is the leading exchange in this sub market. Hence, when modelling EEX prices the whole EU-4 electricity sub market consisting of the mentioned countries has to be considered.[2] Additionally, Figure 2 shows monthly spot market prices for other Continental European countries. Historically, Dutch power prices (NL) are on the upper end but due to the mentioned market coupling with France and Belgium (see Footnote 1) prices converged in 2007. On the other side, prices in Eastern Europe (especially Poland – PL) form the lower end.[3]

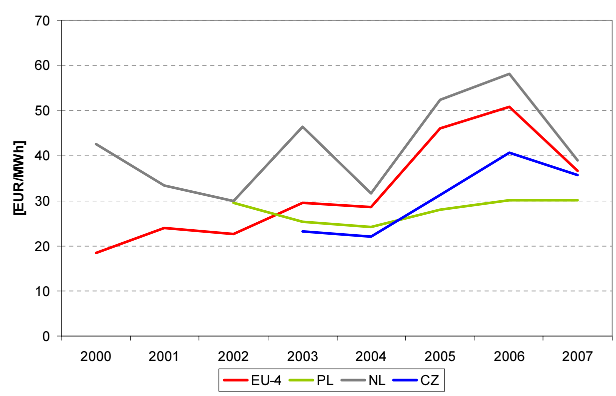

Figure 2
Development of Wholesale Spot Market Prices in Western and Central Europe.
Source: Power Exchanges

To assess the performance of a liberalised electricity market it is of important interest how electricity prices have developed after restructuring. Therefore, a major question for further investigations is whether these prices are a competitive outcome. That is to say, whether these prices do reflect the marginal costs of the generation set or whether they are increased by some kind of market power.

* Reinhard Haas, Christian Redl, and Hans Auer are with the Energy Economics Group, Vienna University of Technology, Austria.
See footnotes at end of text.

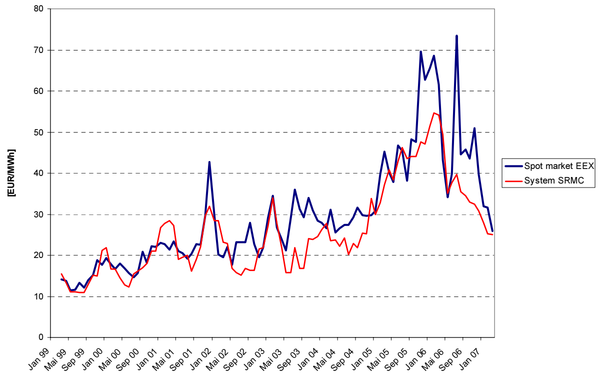

Figure 3
Evolution of Electricity Prices and System Marginal Costs in the Regional Market AT+CH+DE+FR from 1999-2007.
Source: EEX, BAFA, UCTE, own calculations

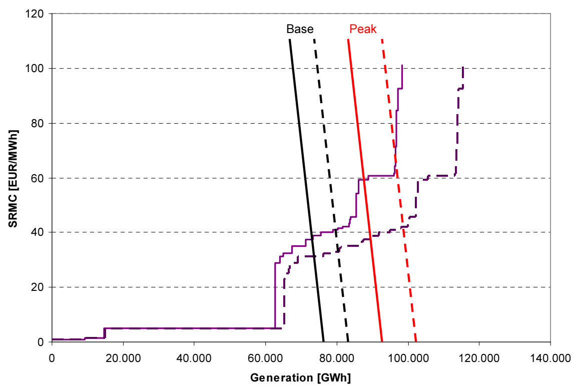

Figure 4
Merit Order Curve for the EU-4 Electricity Market (AT+CH+DE+FR, solid lines) and for the EU-4+2 Market (AT+CH+DE+FR+CZ+PL, dashed lines) for May 2006 and Corresponding Electricity Demand.
Source: UCTE, BAFA, EEX, own calculations

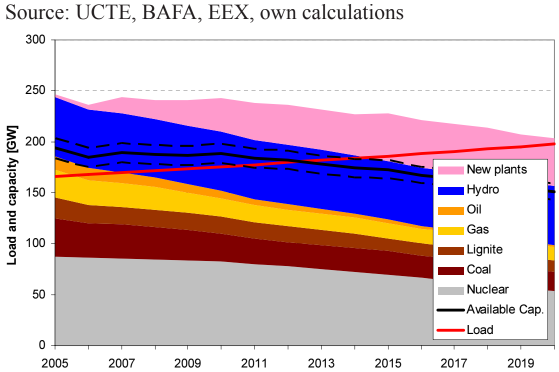

Figure 5
Trends of Generation Capacity and Load in the EU-4 Market.
Source: Platts, national statistics, own calculations

The "Old" Western European EU-4 Power Market

In competitive markets, marginal generation costs are relevant for price formation. Due to the dominance of fossil fuelled power plants in the EU-4 power market, primary energy prices and CO_2 emission allowance prices crucially determine the development of power prices. Besides parameters directly affecting generation costs of thermal plants, also production of infra-marginal technologies (e.g., hydro run-of river and nuclear power) indirectly influences price formation. For instance, in years of increased hydro availability run-of river plants can increase their production. Therefore, ceteris paribus, increased hydro generation replaces conventional electricity in order to meet given electricity demand which corresponds to a shift of the merit order curve to the right. As a result wholesale prices decrease when hydro generation increases.

Figure 3 shows the comparison of realised EEX spot market prices and modelled system marginal costs. The model shows a close correlation of prices and costs from 1999 to 2001 with a structural break in December 2001. Prices and costs diverge between June and October 2002 and between June 2003 and November 2004. This mark-up suggests following interpretation. Müsgens (2004) argues in an analysis of the German wholesale market: "The difference between marginal costs and prices is attributed to market power. …there is strong evidence of market power in the second period from September 2001 to June 2003". In late 2006 and early 2007 prices again significantly diverge from the competitive benchmark model.

Taking a closer look at electricity supply, one can identify a strong convexity of the merit order curve with a high slope of the supply curve when approaching system capacity limit. Figure 4 depicts the merit order curve of the EU-4 power market for May 2006. About 50% of total generation stems from power plants with low short run marginal costs. These comprise run-of river hydro power plants, "new" renewable plants which are subject to national support schemes and, finally, nuclear power plants.[4] Generation costs of fossil fuel power plants are much larger resulting in a huge jump in the merit order curve whereas the ranking of conventional thermal power plants changes depending on the prevailing fuel and CO_2 price level.

As in many electricity markets that have been liberalised, most European countries started liberalisation with significant excess capacities in generation – built up in the time of regulated area monopolies. Indeed, it was a common motivation and driver for introducing competition.

Yet, excess capacity in generation plays a core role in the restructuring process of an electricity supply industry. If utilities compete with excess capacity in generation – which also depends on transmission capacity - the price they receive for electricity will be equal to their short term marginal cost. Under perfect competition without remarkable excess capacities the price will not rise above the long-run marginal costs of new technologies. But if there is no competition or a too tight capacity the price can be substantially higher than both marginal costs especially when demand is inelastic to price.

Figure 5 depicts the currently looming developments of load and generation capacity.[5] In recent years spare capacity decreased continuously in the EU-4 sub-market (spare capacity = net capacity minus maximum load). In this context, variations and uncertainties in available capacities play a crucial role as indicated by the dashed black lines in Figure 5.

Currently, transmission constraints have a substantial impact on the separation of sub- markets in Continental Europe. Hence, another important prerequisite for a sufficiently wide market would be that there is sufficient transmission capacity to neighbouring regions, increasing the number of potentially competing generators. Figure 6 depicts the situation at cross-border transmission lines for the year 2006.

The effects of extending the EU-4 market by completely integrating the markets of the Czech Republic (CZ) and Poland (PL), both electricity exporting countries, will be analysed in the following. A precondition for this market extension in the short run is making more cross-border transmission lines available due to a reduction of long-term contracts.

However, apart from lacking incentives for TSOs to invest in new interconnector capacities, the sector inquiry by the European Commission notes that a significant proportion of existing cross-border lines is still allocated on the basis of long-term contracts (EC, 2007).[6]

For example, at the Austrian-Czech border 150 MW of interconnector capacity for 2007 were auctioned in winter 2006.[7] This relates to 40 to 60% (with respect to summer and winter values) of Net Transfer Capacities (NTC) for 2007 published by the European Transmission System Operators (ETSO). Results of this auction yielded a capacity price of 4 EUR/MWh reflecting market participants' expectations on wholesale price differences.

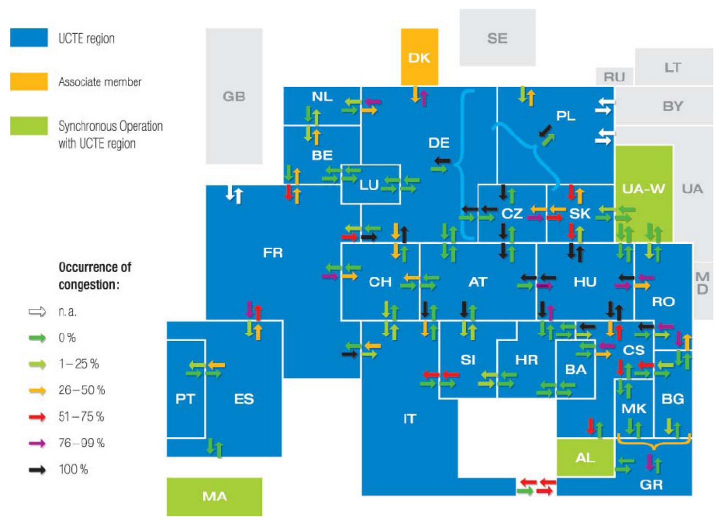

Figure 6
Cross-border Congestion in Continental Europe for 2006.
Source: UCTE (2007a)

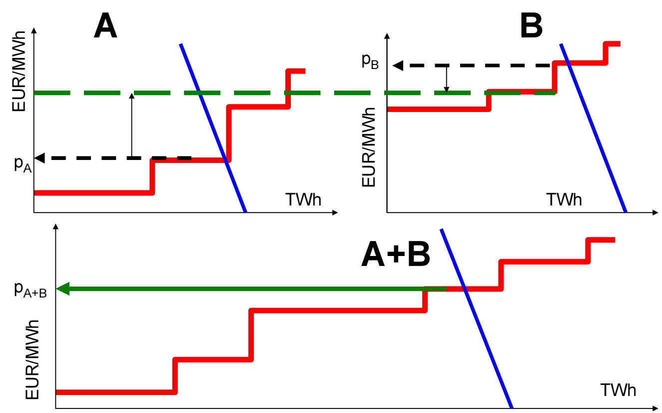

Figure 7
Effects of Market Extension in an Electricity Market

"Market Coupling" of the Western and Central European Electricity Markets

Figure 7 shows the theoretical result of market coupling of a low price market A (with "cheap" excess capacity, e.g., the Czech Republic) and a high price market B (with no "cheap" excess capacity, e.g., the EU-4 market). As a result prices increase in market A which goes along with an increase in producer surplus in market A whereas prices decrease in market B increasing consumer surplus in B. Of course, sufficient cross-border capacities must be made available at low costs.

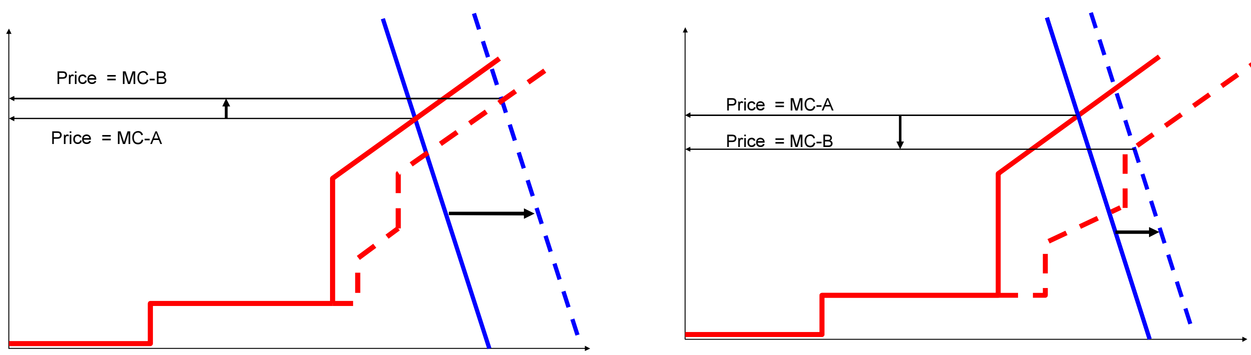

Figure 8
Effects of Integrating a "Short" Country (left) and a "Long" Country (right) in an Existing Market

Figure 8 depicts the effect of full market integration for two different cases. In the first case, adding a "short" country B – a typical import country with demand exceeding capacities – results in price increases for the extended market compared to the former single market A. On the other hand, when a

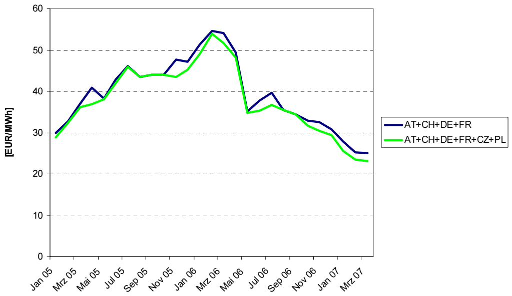

Figure 9
Price Effect of a Hypothetical Market Coupling of the EU-4 and the Czech Republic and Poland.
Source: EEX, BAFA, UCTE, national reports, own calculations

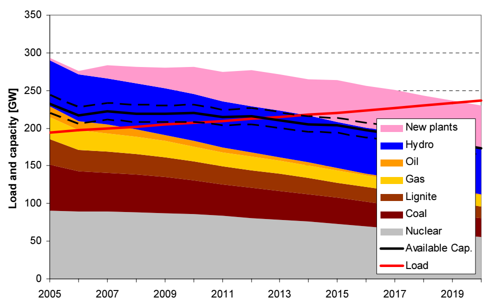

Figure 10
Trends of Generation Capacity and Load in an Integrated Market Consisting of AT, CH, DE, FR, CZ and PL.
Source: UCTE, Platts, national statistics, own calculations

"long" country B – where demand is less than installed capacities – is added prices decrease for the extended market compared to the single market A.

Finally, Figure 4 also shows the effects on supply when the Czech Republic and Poland become part of the Western European market. Hence, the dashed curve shows the hypothetic merit order for AT, CH, FR, DE, CZ and PL for May 2006. As can be seen, especially in the medium load segment of the supply curve a flattening is the result of the market extension which, in theory, could have the potential of reducing prices in the "old" EU-4 market.

The effects of market extension in the EU-4 countries by the Czech Republic and Poland are shown in Figure 9. Due to the mentioned flattening of the supply curve prices decrease slightly compared to the situation where only AT, CH, FR and DE form the market. Clearly, price increases result from this market extension in PL and CZ.

Clearly, "positive" price effects for the "old" EU-4 countries due to market coupling with the Czech Republic and Poland only occur as long as these two countries have enough excess capacity. The following will show the little likelihood of this scenario.

In Figure 10 the effects of extending the market by the Czech Republic and Poland are shown. Compared to Figure 5 no improvements concerning security of supply can be expected from this market coupling.

Central Europe (i.e., the Czech Republic and Poland in the context of this paper) has adequate generation capacity for the foreseeable future. Nevertheless, after 2010 supply security will also become negatively affected due to lack of power plants being built and pronounced decommissioning of existing power plants (both nuclear and fossil fuelled plants). One remaining major uncertainty in these countries is the magnitude of demand growth.

Conclusions

Currently, in Western Europe there is virtually one joint electricity market in Austria, Germany, France and Switzerland with one market price. France and Germany play a key role within this market because of their size and geographically central positions and this market is characterised by a small number of players that dominate the market. This aspect is being reinforced by two others: insufficient transmission capacity is available between adjacent sub-markets; and increasing horizontal integration with natural gas supply.

An extension of this market to Eastern European countries like the Czech Republic and Poland by means of making more cross-border transmission lines available due to a reduction of long-term contracts would lead to a slight decrease in Western European wholesale prices but yield electricity price increases in the Czech Republic and in Poland.

Finally, it is stated that currently in the region still sufficient spare capacities in generation and transmission are available. However, current developments imply upcoming security of supply problems by 2012 in the investigated markets even in case of an extended market.

The definitive litmus test for liberalisation will come in every sub-market in Continental Europe at the point-of-time when the bulk of excess capacities has disappeared and demand has come close to available capacities. That is to say, the most important problem is to provide long term incentives for investments in upgrading and in new generation and transmission capacities, as well as in demand-side efficiency and demand responsive measures. This issue is especially relevant in the context of decentralised vs. further centralised development of the electricity supply system.

Footnotes

[1] In the following, this market will be referred to as "EU-4".

[2] In early 2007 implicit auctions between France, Belgium and the Netherlands have been introduced leading to a coupling of these markets thereby effectively removing the market separation in North Western Europe as depicted in Figure 1. Nevertheless, with regard to mid-term supply security perspectives of the Western European market, this coupling does not alter the arguments presented below since both Belgium and the Netherlands are net-importers of electricity.

(continued on page 31)

Economics of Interconnection

By Jørgen Bjørndalen and Torkel Bugten*

Abstract

The European policy of integrating national electricity markets to create a unified European electricity market necessities increased interconnection between the European countries. The potential benefits of a specific interconnection are important in order to decide which interconnections should be established (first). This paper addresses how especially the long term effects can be identified. It follows from the discussion in the paper that in order to cover all potential effects, a rather complex model will have to be employed, or one has to rely on various partial analyses.

This article was first motivated by a claim from the Dutch regulator DTe during the licensing procedure for NorNed that there would be no long term welfare effects from an interconnection. We strongly disagree.

Introduction

The aim of this article is to present the underlying economic foundations for an assessment of the value of interconnections between thermal and hydroelectric power systems. In particular, we are concerned with the long-term impact on welfare.

We will use two different approaches. First, we consider the short-term effects. Second, we consider the impact of interconnections on long-term equilibrium.

The impact of uncertainty is not included explicitly in the analysis. As a consequence, we have not analysed formally how an interconnection would affect the dynamics of investment decisions.

The article is to a large extent based on our experience from analyses of the NorNed project, which is a new 700 MW interconnection between Norway and the Netherlands.

Short-term Impacts

Assume two perfectly competitive electricity markets; one is a thermal based market, whereas the other is predominantly a hydro-based system. Without interconnection, the two markets are likely to have quite different price structures. When such markets are interconnected, the trade between them will, in the short term, have an impact on price formation, production and consumption in both regions. In hours with higher prices in the thermal system, there will be imports from the hydro market, and vice versa. Mobilising increased output from the hydro (thermal) suppliers would imply a certain price increase in the hydro (thermal) market. This price increase would then imply adjustments in consumption, and/or reduced hydro production during other periods, and/or reduced export to other neighbouring countries. These price changes will change producer and consumer surplus in the short term, and will also have distributional impacts across markets.

The size of these adjustments depends on the price elasticity of demand and supply in the regions in question, and to which extent the regions are interconnected with other markets as well.

A main benefit observed in a competitive model origins from the absolute value of the price difference between the new market prices, aggregated over the lifetime of the interconnection. This is often referred to as the Trading Margin. Newbery (2004) provides a brilliant overview of how the trading margin between a thermal and a hydro system is created.

Change in Local Consumer and Producer Surplus

It is fair to believe that the change of market prices in the hydro system will not change total output from the hydro power plants – reduced prices in one period will lead to increased production in other periods. Total output from the hydro system is constrained by precipitation, and is exogenous with respect to the interconnection. For the thermal market, reduced prices in one period will lead to reduced production for this period. Increased prices will similarly lead to increased production in other periods. However, there is no direct link between the reduction in one period and the increase in another period (unless the power plants face very strict market conditions for the contracted fuels or emission costs, e.g., if the opportunity cost of unused fuel is zero). A schematic illustration for a thermal market is thus slightly different from a corresponding illustration for a hydro market, as the short-term supply curve is not a horizontal line in the thermal market cases.

In the sketches below, it is assumed that the trade with neigh-

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See footnotes at end of text.

bouring countries remains unaffected by the price changes imposed from the trade via the interconnection studied.

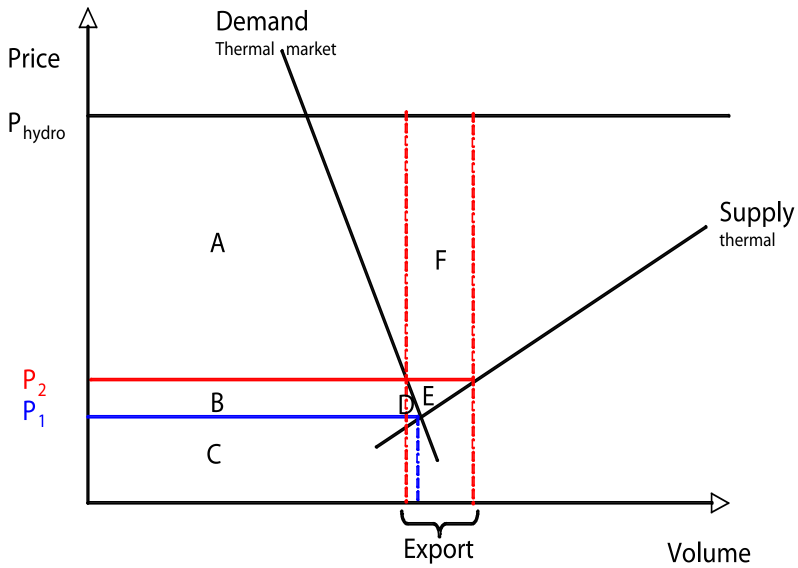

Figure 1
Thermal Market Exports to Hydro Market

Thermal Market During Low Load Periods[1]

Let us first consider the export from the thermal market. Figure 1 pictures a typical off-peak situation with a relatively low price in the thermal market. Hence, off-peak trade would typically imply increased thermal production, potentially reduced consumption and export to the hydro system. The price difference between the two markets will be reduced somewhat because of the trade. Thus part of the potential trading margin will be shifted to producers in the thermal market, instead of the owner of the capacity.

The consumers will experience increased prices, from P_1 to P_2, and the consumer surplus will change from areas A, B and D to just A. The producers will see their producer surplus increasing from C with B, D and E. We assume that the thermal market's share of the trading margin is γ, and the share of the costs for the interconnection is β. Thus the thermal country will receive γF, F being the trading margin. Finally, we let X be the operation and maintenance costs plus annuity of the fixed costs, discounted with the correct (societal) interest rate. The welfare accounts for the thermal market will then be as follows:

- Change consumer surplus: -B-D
- Change producer surplus: +B+D+E
- Change trading margin: +γF
- Cost of interconnection: -βX
- **Total change: +E+γF-βX**

We note that the size of E depends on how steep the supply and demand curves are. The area will be larger the less elastic (steeper) the demand and supply curves are. We note that the smaller E turns out, the larger will F be. Whereas F is the trading margin, E is the part of the potential trading margin that is shifted to the participants in the thermal market.

The assumption that an increase in interconnector capacity will not affect the trade with other countries is typically not true. The changes in domestic prices will tend to influence the volumes traded (and thereby also the prices in the other countries), or the trading margin on other interconnectors. These changes will in general not have important effects on total welfare, but will lead to a redistribution of income between the countries involved.

An important question is whether it is possible to say anything ex ante about the slope of the supply curve and the demand curve during peak and off-peak situations. We note that in addition to cost functions of thermal power plants, this also depends on producer behaviour in the thermal market during off-peak situations. How do the producers behave in a specific hour when spot price is insufficient to cover marginal costs, but stop and start costs makes it unprofitable to stop the plant? It is commonly observed that thermal power plants are kept running despite variable costs above the prevailing spot price. Due to start and stop costs, this might also be optimal for the plant.

SKM (2003), which takes supplied volumes under peak and off-peak into consideration, and thereby calculates volume weighted average prices, reports a significant transfer of wealth from producers to consumers. This corresponds to a statement that area B during import (transfer from producers to consumers) is significantly higher than B+D under export.

The European Inter-TSO compensation scheme (ITC) implies a redistribution of income between TSOs affected by international trade. ITC does not directly influence market prices and trade, but the trade patterns influence the amounts paid/received by the TSOs. It should, therefore, be accounted for in cost-benefit analyses of new interconnectors.

Other Short Term Effects

In the short term, there are also other sources of potential benefits:

- Increased competition and improved market liquidity.
- Interconnection with a hydro system will tend to stabilise demand towards the thermal system. This will increase the expected operation time and thus improve the investment climate for base-load generation as well as the average fuel efficiency.
- Security of supply can be improved. As shown in the next section, the results with respect to security of supply in the long run are ambiguous and depend on the assumptions applied in the models.
- Interconnection with hydro systems will also give the thermal market access to hydroelectric balancing services.

Long-term Analysis

Competitive market players handle production investment and operation, while transmission investment and operation is handled by TSOs (and regulators). Both production and transmission assets will be part of the long-term equilibrium. In this respect, it is important to bear in mind that if the TSOs do not implement profitable grid investments, the long-term equilibrium will be less efficient than it should have been. One cannot expect the market players to invest in grid assets if TSOs don't.

Theoretical Analysis

In the long run, transmission and production investments are to some extent substitutes. This is in fact one of the reasons why transmission capacity is attractive from a welfare perspective – it may be an efficient way of providing power when local production is expensive.

We have based the analysis on three different approaches, where we compare the equilibrium in a thermal system with and without an interconnection to a hydro system[2]:

- A two period, one technology model, with constant marginal costs
- A four period, four technologies model
- A two period, one technology model, with variable marginal costs

Two Periods, One Technology, Constant Marginal Costs

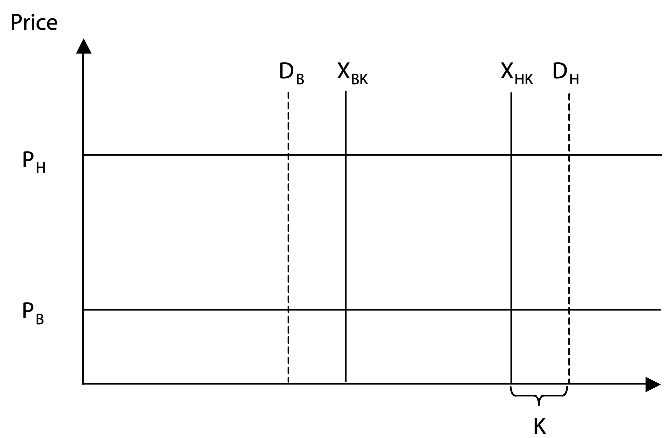

Figure 2
Interconnection in a Single Technology Model

The simplest two period model assumes a production technology with a per unit capacity limit and constant marginal costs up to that limit. For simplicity, demand is assumed to be independent of prices (no price elasticity, D_B and D_H). It is also assumed that base load and high load periods have the same duration. The long-term equilibrium is shown in the figure below:

Without interconnection, production equals demand in both periods. In base load, the price will be equal to short run marginal costs (SRMC), as capacity is not a scarce resource in this period. The peak load price must then be such that it covers both the SRMC as well as the capital costs of the production units. That is, peak load price must equal SRMC + a, a = capital costs / production. If the price is lower, producers will in the long run not be able to cover their full costs and will go out of business. If the price is higher, new production units will be attracted to the market.

Assume then that the price difference makes it profitable to build an interconnection. Imports will then replace some of the high load production (X_{HK}), leading to a reduction in production capacity equal to the capacity of the interconnection (K). In base load, production will increase by the volume exported (X_{BK}). Domestic production costs are reduced by the capital cost of K production units. The reduction in operational costs during high load is exactly offset by an increase in operational costs during base load. Prices, and thereby the consumer surplus, is not affected. The owner of the interconnection will then capture all of the gain from reduced production costs (a*K).

The interconnection can be seen as a storage for electricity, making it possible to produce power during base load and consume it during high load. This kind of storage should be expanded until the price difference between base and high load exactly covers the costs of storage. With the assumptions used in this model, the long-term equilibrium including storage (or interconnections) implies that production capacity is replaced by interconnections until the production capacity is fully utilized in both base and high load.

Four Periods, Four Technologies

von der Fehr and Sandsbråten (1997) present a power market model with four periods (base load, medium-run, high-run and peak load) and four thermal production technologies. Each of the technologies is the marginal technology in each of the periods, both with and without the introduction of an interconnection.

With respect to production capacities, an interconnection with a "one unit" capacity implies that (in their day-night power exchange):

- Peak load capacity is reduced by two units
- High-run capacity is increased by two unit
- Medium-run capacity is reduced by two units
- Base load is increased by one unit

The interconnection then implies that the new optimal level of installed capacity is one unit less than the initial equilibrium. Prices and consumer surplus are not affected. Again, the owner of the interconnection captures the gain from reduced production costs – in the form of a trading margin.

The results from both this and the previous model are driven by the model assumptions, particularly the assumption that there is no change in which technology is the marginal one in each period. From this assumption, it follows that prices are unaffected by the interconnection. As will be demonstrated below, it is quite easy to develop a numerical example with different conclusions.

Two Periods, One Technology, Variable Marginal Costs

The purpose of this model is to examine the effects of an interconnection in a situation with a more continuous supply function, as opposed to the stepwise linear functions in the previous two models. The model is equal to the constant marginal cost model, except that each production unit has no capacity limit, but instead an increasing marginal cost function. The number of units and their production during high load is determined by costs and the difference between high and base load consumption. For computational convenience, a rather simple cost function is assumed:

$$C(Z, X_H, X_B) = A \cdot Z + \frac{X_H^2}{Z} + \frac{X_B^2}{Z}$$

Here, Z is generation capacity, A is the fixed (capital) costs associated with Z, and X_H and X_B is actual production during High and Base load.

With this model, it turns out that prices are affected by interconnection, such that an interconnection reduces high load prices and increases base load prices. In sum, the interconnection implies an increase in consumer surplus. This result has a rather intuitive explanation. As shown by the previous models, the interconnection leads to a reduction in production costs, as producer surplus is always zero in the long run. A reduction in the difference between high and base load prices then means that some of the potential income for the owners of the interconnection is transferred to the consumers. This result is in fact the same as described in the section about short-term effects. Although the change in producer surplus in the long run, due to an interconnection, will be zero, the change in consumer surplus will not be zero.

The model also has some interesting features with respect to production capacity. In a numerical example, an interconnection with a capacity of 17% of high load consumption leads to only 2% reduction in the production capacity. This is a quite different result from the one obtained in the other models. We arrive at this result as we have departed from the commonly used and simplifying assumption that prices will not be affected by the interconnection.

Concluding Remarks

Using simple models of perfect competition with realistic assumptions, we have demonstrated that interconnectors will create persisting benefits for consumers and producers, in addition to the trading margin.

The models arrive at different conclusions regarding security of supply, measured by available production and interconnection capacities. In the models where prices are assumed unaffected, the increase in interconnection capacity is offset by a similar reduction in production capacity. In the model where the interconnection affects prices, the numerical example shows a substantial increase in available capacity.

In real life, the production technologies are arguably more diverse and flexible than assumed in the first two models. Interconnections will most likely improve security of supply, by increasing total available capacity.

Our analysis has focused on the benefits of interconnection related to the spot market. In principle, similar benefits can be obtained if the interconnector capacity is used for trading balancing power and system services.

Many countries have ambitious targets related to developing renewable power. Linking a thermal market to a hydro system improves the ability to increase the market share of green, but inflexible generation, such as windmills.

We believe that interconnector investments will be most efficiently provided for by considering them as part of the core business of the TSOs. In such as setting, interconnections, as well as all other transmission investments, should be evaluated from their welfare effects.

Given the complexity of a real electricity market, a very complex model will have to be employed in order to capture all the potential benefits. Alternatively, one has to rely on several partial analyses. This approach though, has the disadvantage that one cannot really be sure to which extent the "partial" benefits/costs are additive or not.

Footnotes

[1] During peak load, the thermal market will typically be importing from the hydro market, but the welfare impact will be similar.

[2] The hydro system is characterized by less intra day price volatility than the thermal system, meaning that the interconnection will be used for imports to the thermal system during high load and exports during base load.

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Mid-term Perspectives for the Western/Central European Electricity Market *(continued from page 26)*

[3] In 2007, Czech power prices (CZ) almost reached Western European levels for a number of reasons. CO_2 certificate prices fell dramatically during 2007, nuclear production decreased in the Czech Republic and more cross-border capacities became available due to a reduction in long-term contracts between Germany and the Czech Republic.

[4] Clearly, some "new" renewable energy sources are associated with high variable costs (e.g. biomass). Nevertheless, from a wholesale market point of view, these technologies – in the short run – decrease residual load which has to be met on the conventional markets (see also Sensfuss et al. (2007)).

[5] The figures for the trend in generation capacities are based on existing capacities, approved new capacities, decommissioning of nuclear according to IAEA and a limited lifetime of fossil plants of 40 years. Load forecast is based on an earlier study of the authors.

[6] In 2005, on the Czech Austrian border 60-70% of interconnector capacity was reserved for long-term contracts (EC, 2007).

[7] See www.auction-office.at for results of cross-border auctions at the Austrian borders.

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1st IAEE Asian Conference – A Summary

The 1st IAEE Asian Conference held in Taipei on November 5 to November 6, 2007 was a big success. A total of more than 300 participants from 18 countries worldwide, including from Taiwan, contributes the success of the Asian Conference. The main theme of the conference is "Asian Energy Security and Economic Development in an Era of High Oil Prices" and over 60 papers were addressed in 1 plenary session, 1 special workshop session, and 12 concurrent sessions.

At the conference ceremony on November 5, Dr. Wenent Pan, the President of Chinese Association for Energy Economics (CAEE) sincerely welcomed all participants and expressed his appreciation of participants' contributions to the conference. Mr. Fadah Hsieh, the Vice Minister of Ministry of Economic Affairs, Republic of China, was invited to address the Welcome Remarks. Immediately after the opening ceremony, Dr. Wenent Pan chaired the keynote plenary session and introduced Dr. Mohan Munasinghe and his presentation. Dr. Mohan Munasinghe, the Chairman of Munasinghe Institute for Development (NIND), and the Vice Chairman of Intergovernmental Panel on Climate Change (IPCC), gave the brilliant presentation entitled as "Energy, Climate Change and Sustainable Development – Applying the Sustainomics Framework." Dr. Mohan Munasinghe has shared Nobel Peace Prize 2007 with IPCC for his great contributions. The splendid opening brought the conference to a wonderful beginning.

During the conference, all participants had a lot of heated discussions in the concurrent sessions. The only one plenary session, organized by IAEE 20007 Asian Representative Mr. Kenichi Matsui, was held on the morning of November 6 and the theme is "International Energy Regimes and Initiatives in Asia." Invited speakers included Dr. Sergey Popov of Asia-Pacific Energy Research Center, Sueo Machi of Forum for Nuclear Power Plant in Asia, Dr. Yonghun Jung of Asia-Pacific Energy Research Center, and Dr. ZhongXiang Zhang of East-West Center.

The 1st Asian Conference also provided several interesting social and cultural programs beside the professional programs. Many delegates around the world appreciated these programs: Welcome Reception, Opening Reception, and Farewell Dinner. They chatted, laughed, and applauded. They stunned when students of Chinese Music Department of Chinese Culture University (CCU) played euphonious melodies at the Welcome Reception. Claps were heard after the students of Chinese Martial Arts Department gave a wonderful performance expressing the beauty of the Chinese culture.

As the first regional conference in Asia, the 1st IAEE Asian Conference has been greatly appreciated by all attendants and they look forward to the 2nd Asian Conference in Australia in 2008. Conference organizer, Dr. Yunchang Jeffrey Bor, and his team have built the milestone of establishing the IAEE Asian Conference.

Yixuan Linda Chen

Members of the HKAEE (Hong Kong Affiliate) enjoy the conference.

Dr. Wenent Pan, President of CAEE

Mr. Fadah Hsieh, Vice Minister of MOEA

Dr. Mohan Munasinghe, Vice Chairman of IPPC

Prof. Andre Plourde, President of IAEE

Dr. Yunchang Jeffrey Bor and Mr. David Williams at Welcome Reception in Chinese Culture University on November 4

Concurrent Session 2 on the morning of November 5

Mr. Kenichi Matsui, Councilor of Institute of Energy Economics, Japan

Mr. Edward K. M. Chen, Chairman of Taiwan Power Company

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Investment in Electricity Generation and Transmission in Nigeria: Issues and Options

By Akin Iwayemi*

Substantial expansion in quantity, quality and access to infrastructure services, especially electricity, is fundamental to rapid and sustained economic growth, and poverty reduction.[1] Yet, for the past three decades, inadequate quantity and quality and access to electricity services has been a regular feature in Nigeria, a country with 140 million people with a majority living on less than US$2 a day. The electricity industry, dominated on the supply side by the state-owned electricity utility, National Electric Power Authority (NEPA), and succeeded by the Power Holding Company of Nigeria (PHCN), has been unable to provide and maintain acceptable minimum standards of service reliability, accessibility and availability.

Nigeria's electricity crisis is striking for a variety of reasons. First is its occurrence despite the enormous endowments of non-renewable and renewable primary energy resources. The resource endowments of crude oil and natural gas currently estimated at 35 billion barrels and 185 trillion cubic feet, trespectively, are more than adequate to fuel much of Sub-Saharan Africa (SSA) energy demand for several decades.[2] Coal reserves are also substantial at 2.75 billion metric tons. Also, large amount of renewable energy resources including hydro electricity, solar, wind and biomass energy are present. One of the many paradoxes in Nigeria is energy/electricity poverty amid plenty. Second, despite being a world ranking exporter of liquefied natural gas (LNG), Nigeria's gas-dominated electric grid experienced frequent collapse linked largely to inadequate gas supply. Gas pipeline vandalisation associated with resource control-linked militancy in the oil producing Niger Delta has compounded the supply problem. Huge gas flaring has been a regular feature of the Nigerian oil industry since production began in 1958.[3] This wasteful gas flaring has consistently ranked Nigeria among the world's largest source of carbon emissions, a major factor in global warming. Third, the several billion dollars of public investment that went into generation and transmission capacity expansion in the past decade contrasts sharply with the extremely poor outcomes measured by frequent power outages and voltage variation.[4] Fourth, there are the high social, economic and environmental effects of poor public power supply and its extensive substitution with highly polluting generators. Anecdotal evidence suggests that Nigeria has one of the highest concentrations of generators globally. The negative impact of the ubiquitous generators on environmental quality and the health of the population has elicited major concerns particularly among environmental and health scientists. Fifth is the depth and duration of the electricity crisis despite the availability of energy resource endowment and two decades of major economic reforms that commenced with the adoption of the Structural Adjustment (SAP) in 1986.

The limited scope of this paper precludes any detailed analysis of the wide ranging impact of the crisis.[5] Unquestionably, Nigeria's electricity crisis significantly undermined the effort to achieve sustained economic growth, competitiveness in regional and global markets, employment generation and poverty alleviation. Arguably, apart from the "curse of oil", the "curse of electricity", apparent in the intractable black-outs and brown-outs and pervasive reliance on self-generated electricity, is the most enduring of the series of economic and social adversity that have battered the Nigerian economy in recent decades.[6] The persistence of the crisis under successive governments seems to suggest that the adverse impact of the "curse of electricity" on socio-economic development and living standards was hardly appreciated. The prolonged dismal electricity industry performance has been the most intractable infrastructural problem and policy challenge in the last half a century.

In recent years, there seems to be a better appreciation of the gravity of the infrastructure problem as apparent in various policy initiatives. This combined with the severity of the service failures made possible wide public acceptability and political feasibility of electricity market liberalization. These developments facilitated the passage of the comprehensive Electric Power Sector Reform Act (EPSRA) in 2005. EPSRA embodies radical reforms which if well implemented should produce a robust and competitive electricity industry where unreliable and inadequate service would be the exception rather than the rule. Two significant outcomes of the albeit gradual implementation of the EPSRA, are: the establishment of a regulatory agency, Nigerian Electricity Regulatory Commission, NERC, in 2005; and the unbundling of the industry into six generation, one transmission and eleven distribution companies in 2007.

Despite recent policy initiatives, institutional developments such NERC, the last minute effort of the previous Obasanjo administration to tackle the crisis through the ambitious National Integrated Power Project (NIPP), the

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See footnotes at end of text.

electricity crisis has not abated. NIPP involved the government constructing several power plants to add 1374 MW new capacity to the grid. Ironically, though, the electricity crisis has deepened, the new government has suspended the NIPP citing constitutional reasons associated with its financing from excess crude funds.

Perspectives on Nigeria's Electricity Crisis

The discussion in this section contains a few historical and contemporary reference points to capture the essence of the nature of the electricity crisis since 1970. Figure 1 shows the trend in transmission and distribution losses. Transmission and distribution losses in the double digits are extremely large by international standards. The system losses are five to six times those in well-run power systems, and are among the highest in the world.[7] The high level of power losses is symptomatic of the technical inefficiency of the industry. Reducing the losses to single digits is a major challenge facing the Nigerian electricity industry.

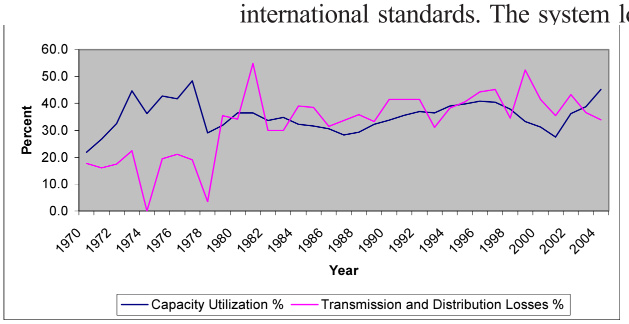

Figure 1
Indicators of Electricity Crisis in Nigeria 1970-2004
Source: Derived from Central Bank of Nigeria Statistical Bulletin Volume 15, December 2004

The trend in capacity utilization in Figure 1 demonstrates another dimension of the electricity crisis. The low and unstable capacity utilization, evident in average capacity utilization of less that 40% during the period, shows the large gap between installed and actual operational capacity. The role of insufficient operational capacity due to ageing facilities that are poorly maintained is indisputable. Notably, despite the size of inoperable capacity, no new plant has been added to the grid since 1990 (Table 1).

Table 1 shows the profile of the hydro-thermal plant mix. Currently gas powered plants dominate the system. The infrastructure facilities are not only old, they are also beset by water flow and gas supply problems. The water flow problems which have seriously undermined the performance of the three hydro stations in recent years are linked to reduced water volumes in the River Niger and its tributaries due to climate change. Increased frequency of gas supply disruptions to gas-fuelled generating plants have also reduced electricity generation. Recently, gas pipeline attacks from associated resource control militancy remains a scourge on the industry.

Station	Plant Type	Installed	Generation Capability	Actual Generation	Year(Units) Installed
Kainji	Hydro	720	303	283	1968,1976,1978
Jebba	Hydro	720	475	278	1983,1984
Shiroro	Hydro	600	600	434	1989,1990
Egbin	Steam	1320	880	839	1986,1987
Sapele	Steam	720	180	179	1978,1980
Sapele	Gas Turbine	300	Not operational		1981
Afam (IV)	Gas Turbine	450	Not operational		1982
Delta (IV)	Gas Turbine	600	210	210	1990

Table 1
Installed and Actual Generating Capacity (Mw) 2004
Source: NEPA, Generation and Transmission Abuja.

Peak demand has been less than half of installed capacity in the past decade, yet, load shedding occurs regularly. This poor service delivery has rendered public supply a standby source as many consumers who cannot afford irregular and poor quality service substitute more expensive captive supply alternatives to minimize the negative consequences of power supply interruptions on their production activities and profitability. An estimated 20 percent of investment in industrial projects is allocated to alternative sources of electricity supply.

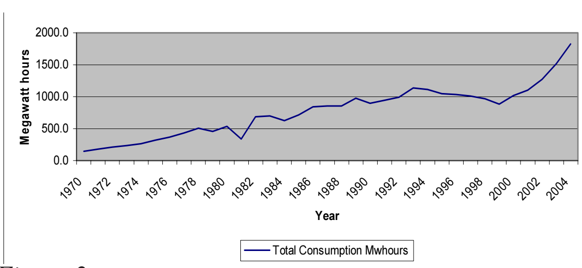

Figure 2
Electricity Consumption 1970-2004 in MWhours
Source: Derived from Central Bank of Nigeria Statistical Bulletin Volume 15, December 2004

The trend in electricity consumption is shown in Figure 2. Three observations emerge from the data. First is the low level of consumption. In 2004 less than 2000 MW-hours of electricity was consumed in a country of 140 million people. Second, the growth rate was relatively low for most of the period between 1970 and 1999 mainly because of suppressed demand line losses. Third is the remarkable turnaround in demand growth in the post 2000 period, a reflection of some improvements in grid supply.

A final perspective on the crisis is evident in the outage experiences of Dunlop PLC, a major multinational manufacturing firm. In 2004, it experienced 316 outages. Outages in 2005 jumped to 405 an increase of 26%. This was followed by an explosive 43% increase between 2006 and 2007, from 553 to 791.[8] Besides, the incidence of outages was 100 in October 2007.

In summing up the discussion in this section, poor electricity service is the outcome of:

- Ageing and poorly maintained generating, transmission and distribution infrastructure facilities failures.[9]
- Weak financial and economic health of the state-owned company NEPA/PHCN. This derived from the prevalence of a regime of price control that had little concern for cost recovery. There were inadequate economic incentives for the company to engage in efficient production and investment behaviour due largely to the price subsidies and cross subsidies. The multiplicity of economic and non-economic objectives associated with state ownership imposed a social welfare-oriented pricing policy that did not generate sufficient profit margin. Notably, the largest debtors to NEPA were the federal, state and local governments.
- Weak institutional framework and governance failures. The institutional and governance failures induced gross inefficiency in production, distorted investment choices and demand patterns, high costs of operation, low return on investment and expensive delays and cost overruns that encouraged widespread corruption.

Producing, Delivering and Accessing Adequate and Reliable Electricity in Nigeria: Issues and Options

Three facts define the scope of the investment problem and enormity of the policy challenges associated with the electricity crisis: the current low level of electricity and energy consumption per capita by global development standards; the dismal state of socio-economic conditions in an economy just recovering from almost two decades of poor performance and deepening poverty; and the low human development indicators.

A look at the numbers in Tables 2 and 3 provides some magnitudes regarding the scope of the investment problem. The wide electricity gap and poverty in Nigeria in comparative African terms are clear from the data.[10] However, meeting the challenges of providing adequate, reliable and widely accessible electricity service involves more than summing up numbers (the mega-watts and the size of investment) and getting other technical things right. The fundamental question is answering the question: what should be done, given the resource endowment, the political, economic, technological, environmental constraints in Nigeria? In fact, the question should be enlarged to include the West African region, given the two ECOWAS initiatives, the West African Power Pool (WAPP) and West African Gas Pipeline (WAGP).

Country	Per Capita Income US $	Per Capita Electricity Consumption (Kwh)
Nigeria	430	140.2
Egypt	1250	1337.4
Algeria	2270	913.6
South Africa	3630	4559.5

Table 2
Electricity and Income Per Capita for Selected Countries in 2004
Source: Energy Information Administration, International Energy Annual 2004. DOE, Washington DC.

	Nigeria	Egypt	Algeria	South Africa
1980	2.240	4.867	2.185	18.383
1990	4.960	11.474	4.657	31.015
2000	5.85	17.861	6.044	39.817
2004	5.888	17.958	6.468	40.481

Table 3
Installed Power Capacity (GW) in Selected Countries 1980 to 2004
Source: Energy Information Administration, International Energy Annual 2004. DOE, Washington DC.

The investment challenge must be appropriately situated in the context of a constrained multi-objective incentive compatible optimization problem. They have several dimensions, namely, size, source, plant mix, security of investment and input supply, human resource requirements, investor/ producer incentives e.g., electricity tariff level and structure, regulatory framework and macroeconomic environment.

From the demand side, the current level of electricity demand underestimates the true level of demand given the high level of suppressed demand. The estimation of potential level and growth in demand must incorporate these factors for greater forecasting accuracy. Power is exported to the neighbouring Niger Republic and there are plans to connect Nigeria with other countries in ECOWAS through the West African Power Pool Project.

Based on these factors and the current decay in the grid, the numbers look staggering. According to a recent projection, generating capacity should increase from 6000 MW in 2007 to 35 GW in 2015, a six-fold increase.[11] This is expected to further triple to 105 GW in 2025 before slowing down to reach 164 GW in 2030. This system expansion is expected to eliminate current electricity poverty and raise electricity per capita from the current extremely low level of 140Kwh to 1,110kwh in 2015, 5,000Kwh in 2030. It is striking that Nigeria's per capita consumption in 2030 will be about 20% above the level that obtained in South Africa in 2003! In addition, since domestic demand must be examined in the context and integrated into the ECOWAS electricity framework, given WAGP and WAPP, and the proposed integrated energy market in West Africa, domestic electricity infrastructure investment and supply policies and promotion must be mutually consistent and coordinated with the rest of the region.

The projected amount of investment to meet this system expansion is estimated at about $262 billion. This amount is enormous given industry experience. Though this financial requirement is daunting, it is achievable. The right institutional framework, policy consistency, appropriate incentive structure and security of investment and input would guarantee the required flow of investment. The successful privatization of the telecommunication industry which brought in about $12 billion of investment provides support for this position. The turning around of a moribund public utility to a vibrant private sector-led industry with one of the fastest system growth rates in the world has been due to the combination of right institutional framework, policy consistency and appropriate incentive structure.

Both domestic and foreign investors and producers have important roles to play in achieving a sustainable electricity future in Nigeria. With the unbundling of PHCN into 6 generation companies, one transmission, and 12 distribution companies the sector is on its way to full deregulation and privatization. The companies are yet to be privatized. There is no universal "one model fits all". But most power systems are private sector driven. A public-private sector mix can also be a viable option.

The peculiar nature and initial conditions in the industry may suggest some roles for the government in the production and delivery of electricity. This is particularly so if only one of the 23 Independent Power Producers (IPP) given licences by NERC to add 8237 MW to existing capacity, has done anything tangible. There is some reluctance among the licensees to begin observable construction activities. Part of the problem concerns the power purchase agreement (PPA) which is at the core of IPP. The unnecessarily long duration of PPA will lock in a high cost structure in the grid system because of the take or pay clause in the agreement. It poses a problem to cheaper production from more efficient plants in the future. The current AGIP IPP agreement is an example. It was partly to prevent being held to ransom that the Obasanjo Administration, as an interim measure close to the end of its tenure, embarked on a rapid expansion of generating plant capacity with assistance from the Chinese government. Three new gas-based power stations are now at various stages of completion. In all, seven power stations were planned to be constructed in the Niger Delta region to utilize flared gas under the abandoned but controversial National Integrated Power Project (NIPP). In addition, a new large 2,600MW hydro project costing US$3.46 billion is also underway, with assistance from the Chinese government. Though the NIPP has been suspended, the decision should be revisited given the reluctance of the private sector. After construction, the plants can be privatized or concessioned to be run efficiently.

Clearly, government intervention through NIPP will moderate the scaling up in tariff that the sector requires to provide affordable and adequate electricity. Power pricing that would guarantee an attractive rate of return to investors adjusted for industry risk and security of investment and input are two important considerations in private sector investment in the industry. Effective implementation of the core reforms in the EPSRA would ensure industry operation based on global best practices.

One of the basic factors in securing the electricity future is the energy mix over the next several decades. Table 4 provides some indicators for alternative energy resources, non-renewable and renewable. While both energy resources will be used in the future, the continued dominance of fossil fuels supplemented by hydroelectricity is envisaged for the foreseeable future. Coal, hydro, solar, biomass, wind and nuclear energy technologies are alternative electricity generation options under consideration.

Energy Type	**Reserves Estimates**
Crude oil	36 billion barrels
Natural gas	185 trillion cubic feet
Coal	2.75 billion metric tons
Hydro	14,750 MW
Solar radiation	3.5-7.0 kwh/m^2-day
Wind energy	2.0-4.0 m/s
Biomass	144 million tons/year
Wave and tidal energy	150,000 TJ/ (16.6 x 106 toe/yr)

Table 4
Energy Resources in Nigeria
Source: Ibitoye and Adenikinju (2007)

Developing and deploying cleaner energy should be part of the investment strategy with the focus, however, on progressively adopting cleaner fossil fuels based on renewable energy sources to meet rural electricity demand. Notably, the government plans to achieve 10% of the electricity supply from renewable resources by 2025.[12] Coal and nuclear energy are also on the options list. 5000 MWe of nuclear generating capacity is expected by 2026.[13] In pursuit of the nuclear power objective, the government and IAEA recently began discussion on identifying possible sites for nuclear power stations.

The mobilization of the financial resources to support a dramatic scaling up of generating capacity, more than twenty-fold in less than three decades, will be a major challenge. Besides this must be situated within the context of the risks that would impact the industry. Risks associated with investment to strengthen power supply networks in both the short and medium term are in four dimensions: economic, socio-political, technological and environmental (methane leaks, climate change compatibility, nuclear accidents spills). Optimal sharing of these risks among the three principal market actors, namely, consumers, investor/producers and the state is essential for efficient allocation of resources in the industry for a sustainable electricity future in Nigeria and the sub-region.

The human resource requirements of robust and reliable generation, transmission and distribution systems, fundamental to a sustainable electricity future in Nigeria, is going to exert significant pressure on the demand for local and foreign skilled workers. Again, as in the telecom industry, having the appropriate incentive structure is essential given the globalized, regional and national demand for skills needed to support a vibrant Nigerian electricity industry, the hub of West African energy map.

Finally, there is the issue of security of supply of gas and gas pipelines associated with resource control agitation in the Niger Delta. Efforts to eliminate tension in the region is more urgent than ever before. Developing and procuring and applying best practices in the industry will impact the volume and quality of investment. The recent flow of gas through the West African Pipeline to power the economies of Ghana, Togo and Benin could also be subject to disruption.

Conclusions

The main conclusions of this paper are that the elimination of the electricity curse and emergence of the required strong investment response are contingent on:

- Radical changes to improve and strengthen industry governance structure to enhance accountability and minimize corruption;
- Strengthening the current reform effort in the industry to create a more competitive electricity market where market-responsive pricing predominates;
- Elimination or minimization of concerns about security of supply of gas associated with resource control agitation in the Niger Delta region. Credible and decisive effort to eliminate tension is more urgent than ever before.

Certainly, a new partnership would have to be forged between the public and private sectors to meet the emerging investment challenges. Ultimately, elimination of the curse of electricity in Nigeria goes beyond delivering adequate and reliable electricity to end-users. It also involves giving consumers widely accessible, affordable and environmentally friendly electricity service.

Footnotes

[1] For specific discussion about infrastructure and economic growth and development in Africa, see World Bank (2000). For more general discussion see World Bank (1994) and (2003).

[2] The share of Nigeria in global reserves of oil and gas is 3% (BP Statistical Review of World Energy).

[3] The persistent flaring of oil-associated gas is partly due to the reluctance of multinational oil companies to invest in the gas gathering facilities for domestic use. Another factor has been their willingness to pay the low penalties for flaring gas.

[4] The amount of public spending on electricity infrastructure between 1999 and 2004 far exceeded what was spent between 1981 and 1998 yet the crisis persisted. $4 billion was spent during Obasanjo's Administration but capacity remained almost static, much below 4000MW.

[5] For discussion on some estimates of the cost of electricity failure in Nigeria at the microeconomic level see Adenikinju (2005)

[6] For more discussion on the curse of oil in Nigeria see Iwayemi (2006)

[7] See Box 9.8 on page 175 World Bank (2003).

[8] See Vanguard Newspaper, December 20, 2007 page 22.

[9] No new generating capacity was added to the industry between 1991 and 2006 despite despite changes in the economy driven by the oil booms of the early 1990s and since 1999 to date.

[10] See Ibitoye and Adenikinju (2005) for some analysis of the future electricity situation in Nigeria.

[11] This is taken from Ibitoye and Adenikinju (2005)

[12] See Energy Commission of Nigeria (2005)

[13] See Energy Commission of Nigeria (2002).

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economy driven by the oil booms of the early 1990s and since 1999 to date.

10 See Ibitoye and Adenikinju (2005) for some analysis of the future electricity situation in Nigeria.

11 This is taken from Ibitoye and Adenikinju (2005)

12 See Energy Commission of Nigeria (2005)

13 See Energy Commission of Nigeria (2002).

Inaugural Event of the Emirates Association for Energy Economics (EAEE)

Emirates Association for Energy Economics (EAEE) Secretary Tilak Doshi, Executive Director for Energy at the Dubai Multi Commodities Centre, welcomed an audience of around 50 people to the EAEE's inaugural event held at the Madinat Jumeirah in Dubai, taking the opportunity to explain the organisation's goals and the factors behind its establishment.

EAEE President Ali Al Yabhouni then introduced keynote speaker Mr. Guy Caruso, Administrator of the U.S. Energy Information Administration (EIA). Ali, in his capacity as UAE Governor and National Representative for OPEC, also presented a brief overview on the current state of oil markets and prices. Some of Ali's main points were that speculation on futures markets and a lack of investment in refinery capacity and upgrading are major factors in the recent oil price hikes.

L to R Tilak Doshi, Ali Obaid Al Yabhouni, Ahmed Bin Sulayem, Martin Trachsel and Guy Caruso

Guy Caruso warmly welcomed the idea of setting up a UAE chapter of the IAEE, bringing energy sector professionals together in a region that is playing and will continue to play a major role in this field. In his keynote speech — 'International Energy Outlook to 2030: Implications for the Gulf Region' — Guy presented major findings from the EIA's latest long-term projections for global energy markets through 2030. The key points of Guy's speech were:

- The current increase in energy prices is being driven by supply and demand fundamentals.
- China and India, but also Africa and the Middle East, will be the main sources driving of global energy demand increases.
- The current inadequacy of required investments is a major contributory factor to the tightening energy supply situation.

Guy also took the opportunity to give the audience a brief overview of findings from "Facing the hard truths about energy". This latest report from the U.S. National Petroleum Council (NPC) considers the future of oil and natural gas to 2030 in the context of the global energy system.

Following the keynote speech a wide-ranging question and answer session was held between the speakers and the audience on a variety of issues. Topics discussed ranged from how the US is planning to meet its future growth in LNG demand to the methodologies used by the EIA for making its forecasts.

Current membership of the EAEE stands at 44.

Publications

Ensuring Market Access: The Capacity of Western Canada's Natural Gas Pipeline System. Peter Howard, David McColl, Dinara Mutysheva and Paul Kralovic (2007). Price: C$25,000+GST. Contact: Canadian Energy Research Institute, 150 / 3512 – 33 Street NW, Calgary AB, Canada T2L 2A6. Fax: 403-289-2344. Email: rrees@ceri.ca

Asia's Energy Future: Regional Dynamics and Global Implications. Kang Wu and Fereidun Fesharaki, Editors (2008). Price: US$30 plus $6 shipping and handling per book. Contact: East-West Center, Publication Sales Office, Burns Hall Room 1075, 1601 East-West Road, Honolulu, HI 96848-1601, USA. Phone: 1-808-944-7145. Email: ewcbooks@eastwestcenter.org URL: www.eastwestcenter.org/pubs/2461

Calendar

1-8 March 2008, Washington International Renewable Energy Conference (WIREC 2008) at Washington Convention Center, Washington DC. Contact: William Armbruster. Phone: 202 647-1247 URL: www.wirec2008.org

2-7 March 2008, Natural Gas Strategy Course 9 part 1 at Groningen. Contact: Evanya Breuer, Manager Customer Relations, Drs, Energy Delta Institute, P.O. Box 11073, Laan Corpus den Hoorn 300, Groningen, Groningen, 9700 CB, Netherlands. Phone: +31 50 524 83 12. Fax: +31 50 524 83 01 Email: breuer@energydelta.nl URL: www.energydelta.org

4-5 March 2008, New Build - Europe 2008 at Dusseldorf, Germany. Contact: Lind Dunkley, Event Manager, Progressive Media Markets Ltd, Progressive House, 2 Maidstone Road, Foots Cray, Sidcup, DA14 5HZ, United Kingdom. Phone: +44 (0) 208 269 7812. Fax: +44 (0) 208 269 7804 Email: ldunkley@wilmington.co.uk URL: http://www.modernpowersystems.com/newbuild2008

4-6 March 2008, WIREC 2008 at Washington, DC. Contact: Conference Coordinator, American Renewables, Washington, DC, USA URL: www.americanrenewables.org

4-5 March 2008, Third Annual Conference on "Distribution of Gas: Poised For Take-off" at The Grand, New Delhi. Contact: Gurpreet Kaur, "Distribution of Gas: Poised For Take-off", The India Infrastructure Group, B-17, Qutab Institutional Area, New Delhi, New Delhi, 110016, India. Phone: 011-41688859, 41034615, 9810498985. Fax: 011-26531196, 011-46038149 Email: gurpreet.kaur@indiainfrastructure.com URL: http://www.indiainfrastructure.com/conf.html

5-7 March 2008, Nordic Biogas Conference at Malmö, Sweden. Contact: Annelie Petersson, Research Manager, Swedish Gas Centre, Scheelegatan 3, Malmö, Skåne, 212 28, Sweden. Phone: +46 40 680 07 60. Fax: +46 40 680 07 69 Email: anneli.petersson@sgc.se URL: www.nordicbiogas.com

10-11 March 2008, Asia 2008 - 2nd Intl Symposium on Water Resources and Renewable Energy Development in Asia at Vietnam. Contact: Conference Secretariat, Hydropower & Dams, Aqua Media Intl, Westmead House, Sutton, SM1 4JH, United Kingdom. Phone: 44-20-8652-5261. Fax: 44-20-8643-8200 Email: alan@hydropower-dams.com URL: www.hydropower-dams.com

10-14 March 2008, Underground Gas Storage Course at Groningen. Contact: Evanya Breuer, Manager Customer Relations, Drs, Energy Delta Institute, P.O. Box 11073, Laan Corpus den Hoorn 300, Groningen, Groningen, 9700 CB, Netherlands. Phone: +31 50 524 83 12. Fax: +31 50 524 83 01 Email: breuer@energydelta.nl URL: www.energydelta.org

10-10 March 2008, Refining – Strategic, Operational and Commercial Drivers at 30 Pavilion Road, London, UK. Contact: Viviane Walker, Miss, CWC School for Energy, Regent Houst, Oyster Wharf, 16 - 18 Lombard Road, London, SW11 3RF, United Kingdom. Phone: +44 20 7978 0042. Fax: +44 20 7978 0099 Email: vwalker@thecwcgroup.com URL: http://www.thecwcgroup.com/train_detail_home.asp?TID=37

10-11 March 2008, Gas-To-Liquids at Crowne Plaza Mutiara, Kuala Lumpur, Malaysia. Contact: Peggy Phor, Marketing Executive, IBC Asia (S) Pte Ltd, 1 Grange Road, #08-02 Orchard Building, Singapore, Singapore, 239693, Singapore. Phone: +65 68355110. Fax: +65 67335087 Email: peggy.phor@ibcasia.com.sg URL: www.ibc-asia.com/GasToLiquids

11-12 March 2008, 5th B.C. Power Summit at Wosk Centre For Dialogue,SFU, Vancouver. Contact: Dr. Victor Pogostin, Senior Executive-Conference Developer, Insight Information/ALM Events, 214 King St. W., Ste. 300, Toronto, Ontario, M5H 3S6, Canada. Phone: 1-866.456.2020; 416.777.2020,x.6178. Fax: 416.777.1292 Email: vpogostin@insightinfo.com URL: www.insightinfo.com

11-13 March 2008, Transmission & Distribution Europe 2008 at Amsterdam, The Netherlands. Contact: Elisabeth Brusse, Synergy, P.O. box 1021, Maarssen, 3600 BA. Phone: +31 346 290 775. Fax: +31 346 590 601 Email: elisabeth@synergy-events.com URL: http://www.td-europe.eu

12-13 March 2008, World Biofuels Markets Congress at Brussels, Belgium. Contact: Annie Ellis, Green Power Conferences. Phone: 0044 207 801 6333 Email: Info@greenpowerconferences.com URL: www.worldbiofuelsmarkets.com

12-14 March 2008, World Biofuels Markets Congress at Brussels. Contact: Dana Vogel, Green Power Conferences. Phone: +442078016333. Fax: +442079001853 Email: info@greenpowerconferences.com URL: http://www.greenpowerconferences.com

24-26 March 2008, LNG Fundamentals at Kuala Lumpur, Malaysia. Contact: Mr. Easwaran Kanason, PetroEDGE, 14, Robinson Road, #13-00,, Far East Finance Building, Singapore – 048545, Singapore. Phone: +65 67478737 Email: info@asiaedge.net URL: www.asiaedge.net/page7.php?event=LNG%20Fundamentals

27-28 March 2008, FPSO Asia Pacific at Intercontinental Singapore. Contact: Rita Parasurum, Marketing Manager, IBC Asia (S) Pte Ltd, Singapore. Phone: 6568355160. Fax: 6567335087 Email: rita.parasurum@ibcasia.com.sg URL: www.ibc-asia.com/fpso

27-28 March 2008, LNG Demand & Forecasting at Kuala Lumpur, Malaysia. Contact: Mr. Easwaran Kanason, PetroEDGE, 14, Robinson Road, #13-00,, Far East Finance Building,, Singapore – 048545, Singapore. Phone: +65 67478737 Email: info@asiaedge.net URL: http://www.asiaedge.net/page4.html

14-15 April 2008, Gasification at London, UK. Contact: Andrew Gibbons, Conference Organiser, SMi, United Kingdom. Phone: 44-0-20-7827-6156 Email: agibbons@smi-online.co.uk URL: http://www.smi-online.co.uk/goto/gasification.asp?emref=S85ES231001717&amp

15-17 April 2008, International Biomass '08 Conference and Trade Show at Minneapolis, MN. Contact: Derek A. Walters, Communications Manager, EERC, 15 N 23rd St, Grand Forks, ND, 58202, USA. Phone: 701-777-5113. Fax: 701-777-5181 Email: dwalters@undeerc.org URL: www.undeerc.org

16-18 April 2008, Energy Forum 08: The Future of Energy Provision Worldwide Exhibition & Congress at Barcelona, Spain. Contact: Secretaria Tecnica, Information and Registrations, Montane Comunicacion, Escultor Persejo 70, Madrid, 28023, Spain. Phone: 34-91-351-95-00. Fax: 34-91-351-75-01 Email: info@enerforum.net URL: www.enerforum.net

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