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IAEE Energy Forum

Second Quarter 2008 International Association for Energy Economics

President's Message

Globalization of Crisis or Crisis of Globalization?

It is a pleasure to announce that this issue of our traditional Newsletter has changed its name and dimension; all for better quality, we hope, and to continue to serve the Association's goals.

The new Forum has more pages and hosts more material than our previous format to spur discussions and debate among members.

So I start with a new format myself: I shall propose to you a shorter but "louder" message, in the sense of writing less printed words but setting forth more provocative issues, from an intellectual perspective.

The title suggests the following dilemma: Are we facing a spreading of crises, one after another, in the international market arena or are we at the final showdown, when the entire world market is risking a collapse under the excess weight of globalization?

I admit that the answer is not at all clear.

The idea of "globalization of crisis" is conveying the notion of spreading, or contagion, or spill over effect from one region to another or from one market to another. There are some examples:

The financial crisis of subprime mortgages in the US has thrown echoing effects on the financial stability of the European system. At the beginning, newspapers in Europe desperately tried to minimize the domestic effect, while covering with lascivious indulgence all the details of the American events. Every American banker was obnoxious and depicted as a fraudulent, incompetent, malicious actor because he dared passing the risk of a middle-lower class U.S. citizen to some Snow-white-like naïve and innocent European bank, which in turn was struggling to protect an equally wise and innocent European customer. However, after the usual myopic attitude of the European Central Bank, caring only about inflation, the leadership has been taken by the Fed, who had no hesitation in rescuing a U.S. Bank, injecting public money into the private market. So far, the Fed seems to be right in curbing the spreading of the crisis.

The rate of increase of agricultural commodity exports has risen to 6% in the last biennium (from 4% in the previous period), while production rose only by 2.5%. This is an indication of changing trade flow patterns. Many have argued that Asian needs for more food, coupled with European targets for renewable energy, which calls for increasing non-food usage of land, is destined to create a price crisis worldwide. The Food and Agriculture Organisation has already warned that an emergency in the so-called Low-income Food-deficit countries (mainly Sub-Saharan Africa) will occur, spurred by inflationary food prices. Food import quantities in those countries are estimated to shrink by 2%, while import values will increase by 35%. This will create suffering, but some IMF loan or other international intervention may alleviate the problem.

The recent dollar oil price increase has been coupled with comparable dollar depreciation vis-à-vis the Euro. The idea is that financial speculation against a primary commodity, like oil, attracts funds which leave dollar denominated financial assets. This creates downward pressure on the dollar exchange rate, which is the counterpart of the upper pressure on the price of oil. As usual, financial bubbles will burst, sooner or later, so that market forces are self-correcting. A more severe than expected U.S. recession --- some have argued --- can cure the speculation in oil prices quite effectively: demand goes down and so will the price.

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

31st IAEE
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Bridging Energy Supply and Demand: Logistics, Competition and Environment

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Plenary and Dual Plenary Themes

- Bridging Energy Supply and Demand; Supply Security and Logistics
- Geopolitics of Oil & Gas
- Climate Change & Post Kyoto
- Energy and Development
- Non-Carbon Alternatives, Session Chair: **Carlo A. Bollino**.
- Nationalization and Privatization in the Energy Industry Integration & Competition, Session Chair: **Georg Erdmann**
- Market Integration & Competition, Session Chair: **Einar Hope**
- Energy Efficiency
- Energy Governance in Asia, Session Chair: **Kenichi Matsui**

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Go to www.iaee08ist.org to register online or to download the registration form. The Sheraton Maslak Istanbul Hotel is the main conference hotel. For booking details please visit http://www.iaee08ist.org/?Page=AccommodationTravel . Deadline for Room Reservations: 17st May, 2008. Please reserve early, as the rooms may be full prior to deadline date.

IAEE Best Student Paper Award: IAEE will hold its 2008 Best Student Paper Contest. A prize of US $1,000 will be given for the best paper in energy economics. For further details on application and guidelines, please contact IAEE headquarters via e-mail at: iaee@iaee.org.

Registration is available on the conference website www.iaee08ist.org

But, the idea of "crisis of globalisation" points at the unsustainability of current world developments. Political scientists and political commentators have studied the relationship between markets and politics, in order to affirm that the beneficial era of free market development, of increasing trade flows, of positive correlation between market growth and democracy developments is behind us. Notwithstanding the well known theorem affirming that gains from trade are positive, politics is taking over. Governments attempt to restrict trade, to call for protectionism, to buy private enterprises, to stir financial flows through Sovereign Funds, to control primary resources, and so on.

As economists, as energy economists we should not be pleased; even when the problem is not in the energy market. The temptation of holding hands on the economy has no limit.

Andrea Bollino

Editor's Note

We continue our focus on electricity generation and transmission in this issue and will continue to do so in the coming summer issue as well. The subject clearly elicits a great deal of interest among our readers.

In future issues we will initiate a "Letters to the Editors" column and invite reader comment on the Forum's articles as well as other items of interest. As is usually the case, we will reserve the right to edit letters/comments as necessary.

Shalini Vajjhala writes that problems with siting new powerlines are likely to both reflect siting difficulty associated with major energy facilities and also directly affect it. He describes a quantitative measure of U.S. state-level transmission siting difficulty and highlights the implications of siting costs and uncertainties for the future of the grid

Audun Botterud and Gerard Doorman focus on capacity adequacy in electricity markets. They discuss potential problems for generation investment and describe policies that have been implemented and proposed to address capacity adequacy. Finally, they briefly look at the experiences so far in electricity markets in Scandinavia and the United States.

Paul Giesbertz and Machiel Mulder discuss the economics of interconnection lines linking the Dutch power market to the Scandinavian and the British market. The overall benefits of the NorNed-cable will likely exceed the costs. The value of merchant lines as the BritNed-cable will likely be reduced by the proposals of the European Commission to enhance the independent position of both regulatory authorities and system operators.

Richard Benjamin explains that restructured energy markets face the dual problems of mitigating market power and incentivizing the "right" mix of transmission and generation in load pockets. He argues that the tools of restructuring work best in load pockets when generation is owned and operated by VIUs, rather than merchants.

Lynne Chester argues that market provision of investment in Australian electricity generation and transmission capacity has not materialised sufficiently, since the sector's restructuring, to meet expected future demand due to a combination of market power, transmission constraints and potential climate change policies not because of mixed ownership.

Malcolm Shealy and James Dorian note that a thought experiment shows that even with conservative assumptions about GDP growth and income elasticity of electric demand, Chinese coal consumption and carbon emissions will be significantly higher than projected by major energy forecasting agencies. The risk is that China and the world fail to recognize the magnitude of the tasks ahead

DLW

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

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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

Energy Forum to Accept Letters to the Editor

As reported in the Editor's Notes section of the newsletter, the Board of Editors of the *Energy Forum* encourages members to comment on material in the newsletter via "letters to the editor". A regular column reprinting these will be carried from now on. The editors reserve the right to condense and edit letters as necessary.

Newsletter Disclaimer

IAEE is a 501(c)(6) corporation and neither takes any position on any political issue nor endorses any candidates, parties, or public policy proposals. IAEE officers, staff, and members may not represent that any policy position is supported by the IAEE nor claim to represent the IAEE in advocating any political objective. However, issues involving energy policy inherently involve questions of energy economics. Economic analysis of energy topics provides critical input to energy policy decisions. IAEE encourages its members to consider and explore the policy implications of their work as a means of maximizing the value of their work. IAEE is therefore pleased to offer its members a neutral and wholly non-partisan forum in its conferences and web-sites for its members to analyze such policy implications and to engage in dialogue about them, including advocacy by members of certain policies or positions, provided that such members do so with full respect of IAEE's need to maintain its own strict political neutrality. Any policy endorsed or advocated in any IAEE conference, document, publication, or web-site posting should therefore be understood to be the position of its individual author or authors, and not that of the IAEE nor its members as a group. Authors are requested to include in an speech or writing advocating a policy position a statement that it represents the author's own views and not necessarily those of the IAEE or any other members. Any member who willfully violates the IAEE's political neutrality may be censured or removed from membership.

Siting Difficulty and Transmission Investment

By Shalini P. Vajjhala*

Efforts to find locations for new energy facilities are often associated with the now familiar term NIMBY (not in my backyard) and even more extreme phrases like BANANA (build absolutely nothing anywhere near anything). These acronyms capture some of the problems associated with siting new power plants and power lines, but the issue as a whole is more complex than these expressions suggest. The term siting difficulty, as used here, is defined as any combination of obstacles to the process of finding locations for new facilities, including public opposition; environmental, topographic, and geographic constraints; interagency coordination problems; and local, state, and federal regulatory barriers to permitting, investment, and/or construction. Given the scope of the constraints affecting new projects, siting difficulty is a broad, complex problem for which solutions are not obvious or well understood.

Siting problems are not unique to energy and electricity facilities, but the siting difficulties associated with these projects can be particularly complex, especially in the case of transmission lines. Transmission projects can span states and regions and usually involve highly visible overhead lines regulated by multiple agencies. Moreover, deregulation and the transition to competitive markets have further complicated transmission ownership, financing, and management. Although the United States has one of the most reliable electricity systems in the world, electricity transmission expansion has not matched growing demand. Since the California electricity crisis and the 2003 Northeast blackout, the grid has been the subject of intense scrutiny. A variety of policies and programs have been initiated to boost transmission capacity. One of the most recent examples of these efforts is a mandate in the Energy Policy Act of 2005 to establish federal energy corridors and National Interest Electric Transmission Corridors (NEITC) to streamline siting and permitting of new power lines in critical areas and congested regions across the United States.

This process has been highly controversial, however, highlighting three major hurdles facing individual transmission projects: environmental barriers, regulatory roadblocks, and public opposition. Together these elements of siting difficulty have the potential to significantly impact investment in the grid by prolonging project timelines and adding uncertainty to already complex financing processes. Although corridor designations are intended to alleviate regulatory redundancy and to ensure timely permitting and review of new project applications, the process of siting corridors has itself has faced opposition on environmental and equity grounds. This Catch-22 or the conflicting demands exemplified by the corridor siting process, demonstrates the need for better characterizing variations in siting difficulty across states and regions to inform proposals and strategies for improving both transmission and generation investment.

Quantifying Siting Difficulty

In a recent article in *Energy Policy*, Vajjhala and Fischbeck (2007) develop a measure of transmission line siting difficulty for the continental United States. This measure is based on a carefully constructed set of indicators, including economic variations of the cost of electricity generation within states, proximity of residents to power plants in different states, comparisons of generation and transmission construction rates and capacity additions over time, and perceptions of siting difficulty, gathered through a survey of industry siting experts. These resulting four quantitative indicators of siting difficulty (economic, geographic, construction, and perception) are compiled at the state-level to provide a first-pass analysis of siting issues.

Each of these indicators is 1) separate from the local causes and effects of siting problems, 2) large-scale to avoid results that are driven by individual case studies, and 3) focused on a different aspect of the siting problem. Because of the numerous feedback loops and interactions among the causes and effects of siting difficulty, no single cause or effect adequately represents the overall problem. For example, one possible measure of transmission siting difficulty is the difference between generation and transmission capacity additions; however, this metric could conceivably mask underinvestment in both types of facilities caused by common siting constraints.

By bringing together different datasets representing complementary metrics, this research establishes a framework for characterizing and quantifying siting difficulty that evaluates and aggregates multiple impacts. The selected metrics were combined using principal component analysis to construct the economic, geographic, construction, and perception indica-

* Shalini Vajjhala is a Fellow at Resources for the Future. Email: shalini@rff.org. This article is based on joint research with Paul Fischbeck, professor of Social and Decision Sciences and Engineering and Public Policy at Carnegie Mellon University, published as "Quantifying siting difficulty: A case study of U.S. transmission line siting." Energy Policy 35(1): 650-671.
See footnotes at end of text.

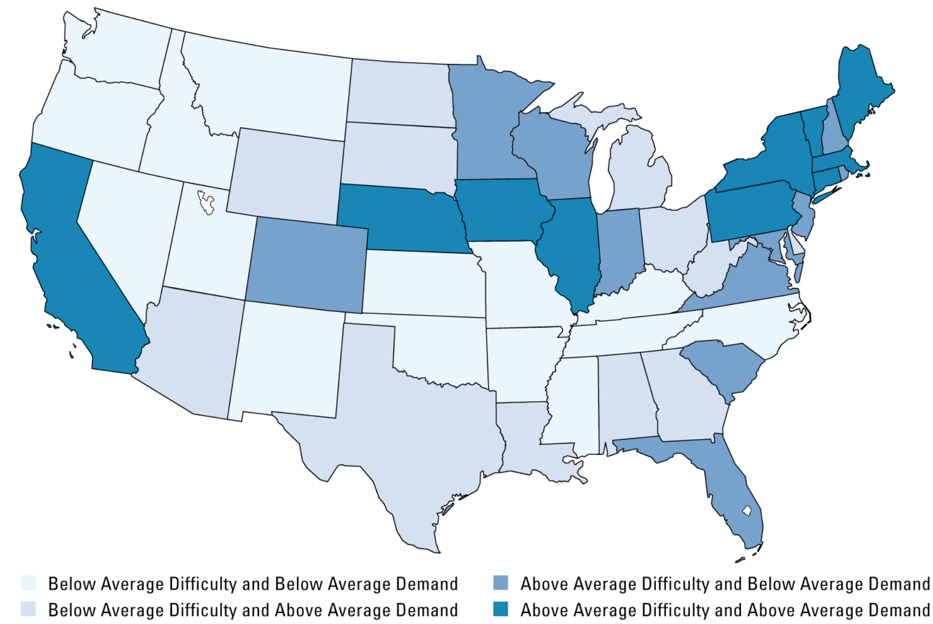

Figure 1

Map of Transmission Siting Difficulty and Demand

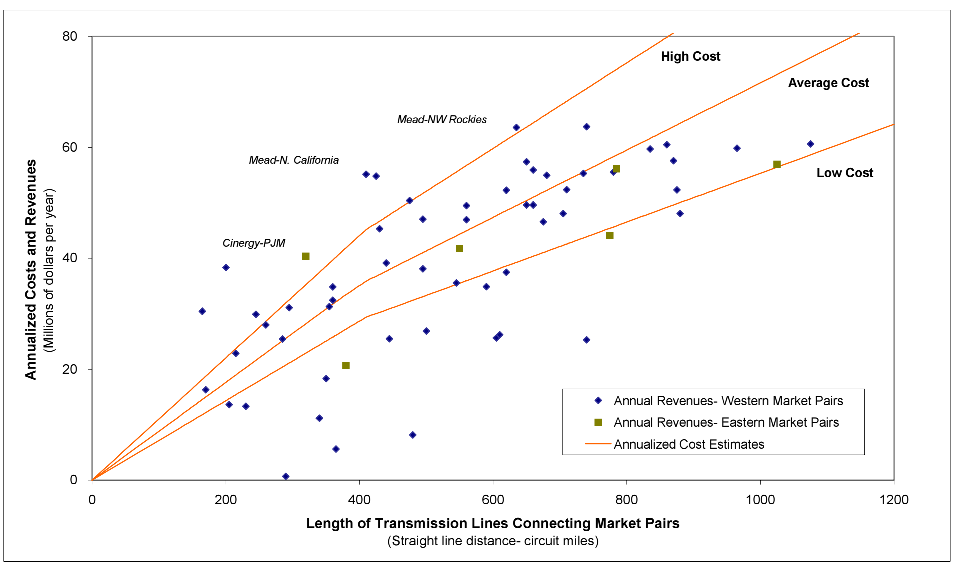

Figure 2
Estimated Revenues and Costs for Hypothetical Transmission Lines Connecting Market Pairs

tors outlined above, and the four indicators were then aggregated using factor analyses. The results of this analysis yield a two factor solution, where the first factor describes state-level siting difficulty and the second factor captures state transmission demand or the need for additional power lines.

Figure 1 illustrates the geographic distribution of these two factors. Scores for both factors range from –3 (very low) to +3 (very high), where 0 is the average demand and difficulty for all states. Transmission demand and siting difficulty are treated as related problems, where states with high need and incentive to build additional transmission capacity are understood to face a variety of constraints (of which siting difficulty is one) that have prevented them from adding lines. The map represents four categories for different combinations of above- and below-average state siting difficulty and transmission demand based on the two sets of state factor scores.

The geographic variations in siting difficulty illustrated here have significant implications for regional transmission development and investment. For example, Regional Transmission Organizations (RTO) face markedly different siting contexts, where the Southeast and Northwest regions of the country have very few states with both high demand for new transmission lines and high difficulty siting them, while the Northeast region has as many as six such states.

Barriers to Investment

Siting difficulty and transmission investment are paired problems. In order to justify construction of any new line, the market for power must provide adequate investment incentive. Policy proposals, like energy corridors, are intended to address cases where investment incentives are inadequate because of the additional costs imposed by siting difficulty. However, even in the absence of siting difficulty, opportunities for transmission investment are highly uncertain. In order to examine the further implications of state-level differences in siting difficulty for investment in the grid, the siting difficulty measure described above was evaluated alongside electricity price data from the Energy Market Reports (EMR). Together these data were used to calculate the potential revenues that could by generated by connecting all possible pairs of EMR markets with new transmission and then examining the relationship between profitability and siting difficulty.

Each point in Figure 2 represents a transmission line connecting a pair of markets and illustrates the potential yearly revenues annualized over a 25-year investment period for a transmission owner of a dedicated 230 kv transmission line. The lengths of the proposed lines connecting 55 pairs of western markets and 6 pairs of eastern markets are estimated as the straight-line distance in miles between market center points. The analysis assumes that the owner collects rents for a transmission line between any given market pair equal to the average annual price difference between those markets.[2]

To compare the potential revenues with possible engineering construction costs, three cost estimates for AC and DC transmission construction are overlaid on the plot. For AC lines, the estimated low cost of transmission is $650,000/circuit-mile, average cost is $800,000/circuit-mile, and high cost is $1,000,000/circuit-mile. These cost estimates are then multiplied by the length of each line, and an annualized cost estimate is calculated based on a payback period of 25 years at a 10% annual discount rate. For lines longer than 400 circuit-miles, DC transmission becomes cheaper than AC transmission; therefore, each of the cost estimate lines includes a break-even pivot point from AC to DC transmission costs at 400 circuit-miles on the graph. For DC lines, the estimated low cost is $400,000/circuit-mile, average cost is $550,000/circuit-mile, and high cost is $700,000/circuit-mile. From Figure 2, revenues exceed average construction costs for approximately 38% of all possible lines at a minimum 10% return on investment.

Based on this simple analysis, if siting costs are not considered, then there appear to be opportunities for profitable transmission investment. Note, however, that project viability in this analysis is defined based on the collective private costs and benefits that could accrue to a group of investors. Transmission ownership is rarely consolidated in the hands of a single owner who sees all the costs and revenues of a project. At a more detailed level of evaluation, these costs and benefits would be disaggregated among various investors and stakeholders, and the viability of any individual project would depend on their allocation. The analysis simply provides an important estimate or upper-bound of the potential benefits and costs of a set of plausible transmission projects.

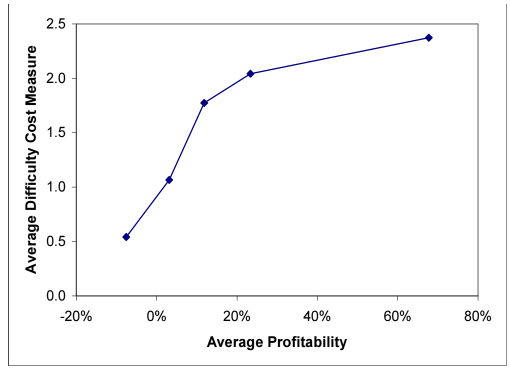

Figure 3
Relationship Between Estimated Profitability of Hypothetical Power Lines Connecting Market Pairs and Distance-weighted State Siting Difficulty Along a Straight-line Route Between Market Pairs.

Since none of the lines in this analysis were under consideration for construction at the time of this study, additional factors, such as siting costs and uncertainty, were assumed to affect total costs, making the lines unprofitable. To examine the impacts of siting difficulty, all lines were ranked by potential profits, divided into five equal groups, and the means of these groups were finally compared with a generic concave siting-difficulty cost measure. The results of this comparison reveal a monotonically increasing relationship between siting difficulty and profitability.

Figure 3 is a graph of this relationship, showing that as the potential profits from a line increase, so do the associated siting difficulty costs. This comparative analysis not only validates the results of the siting difficulty measure, it also highlights the relative importance of siting difficulty to transmission investment. This analysis does not attempt to suggest that any of these lines would be profitable given a detailed evaluation of land costs, rights-of-way, and market uncertainty; nevertheless, it provides an independent validation of the role of siting difficulty as a barrier to transmission investment.

Implications for the Grid

Growing attention to climate policy has brought investments into our energy systems into sharper focus. As a result, many alternatives and proposals for reducing greenhouse gas emissions involve new, large-scale development of facilities ranging from wind farms to coal plants with carbon capture and sequestration to fleets of new plug-in hybrid vehicles. The scale of these proposals has tremendous implications for the future of the grid.

Because many new policy initiatives hinge on the successful development and deployment of large-scale, grid-connected facilities, the difficulties associated with siting new transmission infrastructure provide an important benchmark for the siting problems facing other types of energy investments. Problems with siting new transmission are likely to both reflect siting difficulty associated with new energy development and also directly affect it. As a result, siting difficulty is at the intersection of both technical and policy solutions intended to boost energy system investment. This research makes a first step toward breaking down current siting problems into manageable pieces for evaluation and planning, while simultaneously maintaining a large-scale view of transmission and generation investments on the horizon.

(See footnotes on page 10)

UNVEILING THE FUTURE OF ENERGY FRONTIERS

**** CALL FOR PAPERS ****

December 3-5, 2008 Sheraton Hotel, New Orleans, Louisiana, USA
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United States Association for Energy Economics International Association for Energy Economics
Louisiana Chapter, USAEE

Submission Deadline for Abstracts (with a short CV): July 11, 2008.

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- Oil sands development: challenges and opportunities

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- The implications of an aging workforce
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Legal and Regulatory Considerations
- Siting energy facilities
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**** *CALL FOR PAPERS* ****

Abstract Submission Deadline: July 11, 2008

28th USAEE/IAEE North American Conference

December 3-5, 2008 Sheraton Hotel, New Orleans, Louisiana, USA

Abstracts for papers should be no longer than one to two pages, giving a concise overview of the topic to be covered. Abstracts should comprise of a brief (1) overview, (2) methods, (3) results, (4) conclusions, and (5) references. Please visit http://www.usaee.org/usaee2008/ to download a sample abstract template. NOTE: All abstracts must conform to the format structure outlined in sample abstract template. At least one author from an accepted paper must pay the registration fees and attend the conference to present the paper. The lead author submitting the abstract must provide complete contact details - mailing address, phone, fax, e-mail, etc. Authors will be notified by August 15 of their paper status. Authors whose abstracts are accepted will have until October 16, 2008, to submit their full papers for publication in the conference proceedings. While multiple submissions by individuals or groups of authors are welcome, the abstract selection process will seek to ensure as broad participation as possible: each speaker is to present only one paper in the conference. No author should submit more than one abstract as its single author. If multiple submissions are accepted, then a different co-author will be required to pay the reduced registration fee and present each paper. Otherwise, authors will be contacted and asked to drop one or more paper(s) for presentation.

Abstracts **must be submitted online** to http://usaee.org/USAEE2008/submissions.aspx Abstracts submitted by email will not be processed. Please use the online abstract submission form.

Students: Submit your paper for consideration of the USAEE Student Paper Awards (cash prizes plus waiver of conference registration fees). Students may also inquire about our scholarships for conference attendance. Visit http://www.usaee.org/USAEE2008/paperawards.html for full details.

Travel Documents: All international delegates to the 28th USAEE/IAEE North American Conference are urged to contact their respective consulate, embassy or travel agent regarding the necessity of obtaining a visa for entry into the U.S. If you need a letter of invitation to attend the conference, contact USAEE with an email request to usaee@usaee.org The Conference strongly suggests that you allow plenty of time for processing these documents.

Visit our conference website at: http://www.usaee.org/usaee2008/

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Spanish Affiliate Holds Third Congress

The AEEE held its third congress on the 17th-18th January, at the Euskalduna Palace in Bilbao. About fifty participants from academia, firms and regulatory institutions, met in order to debate and discuss (in the usual way) policy issues and environmental impacts, the liberalization of the electricity sector and the gas and electricity markets. At the first plenary, Professor William W. Hogan (Harvard University) dealt with the regulation and design of electricity markets. Other plenaries included issues related to the price of oil and refining (by representatives of the Basque Energy Agency and Petronor respectively), and the economic impact of the interconnections of natural gas (by representatives of Naturgas). Finally, the Young Investigator Award was presented. Photos adjacent and below show the Congress in session and the Young Investigator Award being presented.

Siting Dfficulty and Transmission Investment *(continued from page 7)*

Footnotes

[1] The total annual price differential is calculated using absolute daily price differences averaged for the selected two-year period (January 1, 1999, through December 31, 2000) at the given prices for 16-hour blocks of on-peak trading and 8-hour blocks of off-peak trading. Transactions between market pairs are assumed to occur for 24 hours a day and 350 days per year at an effective capacity 1,060 MW. The authors acknowledge that the 1999–2000 period reflects unusually high prices because of drought conditions in the Pacific Northwest during summer 2000, examples of capacity withholding, and the impacts of deregulation in California. However, a comparison of the calculated averages with EMR data from January 1, 1997, through December 31, 1997, for the same western markets yields comparable average annual price differentials for both peak and off-peak periods. Additionally, transactions between market pairs are assumed to be small enough that they do not affect long-term market prices and price differentials.

[2] This analysis uses the first 43 most profitable lines based on the average engineering cost ($800,000/ circuit mile). The siting difficulty factor score for each state is rescaled from 0 to 6 and multiplied by a generic concave weighting function in the form (1-e[-x/α]) where the results are robust for a range of values of α > 0. The average distance-weighted siting difficulty scores are then calculated for each line based on the length of line in each state.

Generation Investment and Capacity Adequacy in Electricity Markets

By Audun Botterud and Gerard Doorman*

Introduction

One of the major challenges in restructured power systems is to maintain a level of generation capacity that ensures an acceptable level of certainty against power interruptions. A power market with a well-functioning spot market and long-term markets for allocation of risks between consumers and producers should in theory generate optimal investments in new power generation capacity, but this may not always be the case. In this paper we describe potential problems for adequate generation investments in electricity markets. We also discuss different policies that have been implemented and proposed to address the problem of capacity adequacy. Finally, we look at the experience so far with generation investment in some restructured electricity markets, focusing on Scandinavia and the United States.

Potential Problems for Generation Investments

There are a number of complicating factors that can prevent the electricity spot market from providing sufficient incentives for investments in new power generation capacity. We briefly describe some of the main problems below.

Limited Demand Side Participation

Stoft (2002) describes two demand-side flaws, which can have severe impacts on the price formation in the electricity market. First, the lack of metering and real-time billing limits demand response to price. If there is limited or no short-term price response on the demand side one can end up in situations where the market does not clear and the price must be determined through a regulatory price cap. Unless the price cap is set equal to the value of energy not served, this will give wrong investment signals. Second, the lack of real-time control of power flow to specific customers prevents physical enforcement of bilateral contracts and, therefore, discourages customers from buying long-term contracts.

High Financial Risks in Generation Investment

The risk involved in investing in new power generation is high due to the high volatility in electricity prices. In particular, peak load plants are exposed to the price risk due to their low capacity factor. The long lifetime of generating assets adds to the investment risk. The lumpiness of generation investments may also deter investments, as a new large-scale plant may reduce prices and profitability. Furthermore, a power plant investor faces substantial regulatory risks, both in terms of electricity market design and environmental regulations (e.g., policies to address climate change). Unless there are liquid long-term markets where investors can efficiently hedge their financial risks, these uncertainties can significantly reduce investment in new generation capacity.

Market Power

Market power is often a concern in electricity markets. Industry restructuring has triggered a number of mergers and acquisitions, increasing the market concentration in many electricity markets. Large incumbent companies may choose to postpone generation investments to drive up prices and profits from existing assets, unless the barriers to entry are low for new investors in generation capacity.

Procurement and Use of Operating Reserves

Procedures used by the system operator for procurement and use of operating reserves may distort energy prices and, therefore, investment incentives. If the system operator is willing to reduce the operating reserve requirement in critical peak load situations, this will influence the prices in the energy market. Furthermore, if there is a maximum price paid to generators called upon in real-time, this price effectively caps the price in the day-ahead energy market and thereby reduces the long-run investment incentives.

Market Design for Capacity Adequacy

Given the potential problems outlined above, combined with the detrimental impacts of capacity shortages, it is not surprising that authorities in several countries have not been comfortable with leaving the decisions on generation investments to market forces alone. Below we give a brief discussion of different market

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designs for generation capacity adequacy. The first three schemes are used in existing electricity markets, whereas the last two have been proposed as alternative mechanisms to address capacity adequacy.

Energy Only Market

The electricity markets in Australia, Scandinavia (Nord Pool), United Kingdom and several other European countries are basically based on the energy only market design. In an energy only market, the only revenues to generation owners are through the sale of electricity in the energy market. In each settlement period a market price is established based on the intersection between the supply and demand curves. Under most circumstances prices reflect the operating cost of the marginal generator (if we assume a competitive market). During peak load conditions the price may represent the willingness of the marginal consumer to pay, generating a scarcity rent which compensates for the fixed cost of the marginal peak generators. If there is no demand elasticity, the price should ideally reflect the real value of energy not served during periods of curtailment.

Several of the problems discussed in the previous section may prevent the energy only market from providing sufficient generation investments. In particular, it is important that the prices during peak load situations are not suppressed, so that incentives for new investments are not distorted. Hogan (2005) proposes an adjusted energy only market design, with a demand curve for operating reserves. This will influence prices in the energy spot market and provide better scarcity pricing and investment incentives. Another approach is to have a strategic reserve in the system. This consists of a set of generating units that are kept available for emergencies by the system operator. The strategic reserves should only be deployed when there is a physical shortage of electricity, and the price must be set to a high level, since it effectively caps the spot market price. A combination of a technical, reliability based activation criterion with a price that is higher than any other bids in the market is a compromise that minimizes market interference (De Vries 2004). In the Nord Pool market three of the system operators hold strategic reserves.

Capacity Payments

A capacity payment is a regulatory mechanism that establishes a payment to generators, which comes in addition to the income from the energy market. The capacity payment encourages investments by increasing and stabilizing the volatile income of generators from the energy market. The market designs in Spain, Argentina, Colombia and Chile include a fixed capacity payment, which is administratively determined. The old electricity pool in England and Wales also had a capacity payment, which was added to the half-hourly energy spot prices. The dynamic capacity payment was based on the loss of load probability and the value of lost load.

Capacity Requirements and Capacity Markets

This policy is used in several markets in North East U.S. The objective is to ensure that the capacity levels necessary to maintain system reliability are available. A forecast for a planning period (e.g. years, months, day-ahead) is determined to establish the level of capacity resources that will provide an acceptable level of reliability consistent with agreed upon engineering standards. Based on this forecast, a requirement is established to ensure a sufficient amount of capacity to meet the forecasted load plus reserves to provide for outages, demand uncertainty, and planned maintenance. At the same time, a capacity market is established where load serving entities can purchase capacity in order to meet their capacity obligations.

Financial Reliability Options

Vázquez et al. (2002) propose a regulatory framework based on an organized market where reliability contracts based on financial call options are auctioned. Hence, both the price of the contracts and their allocation among different generating plants are determined through competitive mechanisms. In addition to stabilizing the income of generators and thereby providing incentives for new investments, the proposed mechanism also hedges end-users against the occurrence of high market prices. Similar approaches have also been proposed by Oren (2005). The main advantage of the financial reliability option scheme is that is based more on market mechanisms and demand side participation than the administratively determined capacity payments and installed capacity requirements.

Capacity Subscription

A market design based on capacity subscription was proposed by Doorman (2005). This mechanism requires consumers to install a Load Limiting Device (LLD). The LLD is normally inactive. However, when the demand for electricity exceeds available generation capacity, the system operator activates the LLDs, and each consumer's electricity use is limited by the LLD. Consumers can choose their individual demand limit during LLD activation by buying capacity. In the short run, no new capacity can be constructed. The price of capacity, therefore, represents the consumers' willingness to pay for uninterrupted supply within the existing system. The payments made to producers for capacity represent the costs of keeping generation capacity available, while the price of electricity represents the variable cost of electricity production. Through this mechanism, incentives are introduced for consumers to manage their own loads and rationing occurs in an economically efficient manner. However, the advantages must be weighed against the considerable costs of implementation, including large-scale installation of LLDs.

Experiences so Far from Nord Pool and U.S. Markets

Nord Pool

The restructuring of the Nordic power market started in Norway in 1991, continued with Sweden and Finland in 1996/97, while Denmark finally followed in 2000. Nord Pool is basically an energy only market, but the transmission system operators (TSOs) use additional instruments to ensure system adequacy. The Swedish and Finnish TSOs hold emergency gas turbine reserve capacity. The Norwegian TSO recently also invested in 300 MW gas turbine capacity to ensure energy adequacy in an area with significant transmission constraints. In sum, this emergency gas turbine capacity can be viewed as a strategic reserve, although there is currently not a uniform set of rules for how to use this capacity. In addition, the Swedish, Norwegian and Danish TSOs have established option markets for operating reserves, which help to ensure system security and generation adequacy.

There is little doubt that there was a considerable surplus of generating capacity in Norway and Sweden at the outset of market restructuring. A simple comparison between installed capacity and annual peak load shows a reserve margin of 44 % in Norway in 1990 and 41 % for the whole Nord Pool region in 1995. The Nord Pool market is hydro dominated with about 50% of total generation from hydro. Traditionally hydro power was dimensioned with excess capacity to deal with the high variability in inflow.

Figure 1 shows the development of generating capacity and load in the Nord Pool system since 1994. The figure shows a decrease in installed capacity in 1998 and 1999, when low prices resulted in the closing down of oil-fired thermal capacity. 600 MW of nuclear capacity was decommissioned in Sweden for political reasons in 1999 and again in 2005. The average annual load growth between 1994 and 2006 was 0.9 %, but total demand has hardly changed since 2001, in spite of significant economic growth. The decrease in demand in 2002/03 was caused by a drought in the autumn of 2002, causing an extreme price increase (Figure 2). Figure 2 illustrates the high variability in prices and also shows that the price level has increased after the price spike in 2002/2003. This is partly due to a tighter capacity balance, higher fuel costs, and the introduction of a CO_2 emissions trading scheme in Europe.

To judge if there has been "sufficient" investment in new capacity, we can first compare the present reserve margin with the one in the mid-1990's. The margin has been reduced, but not

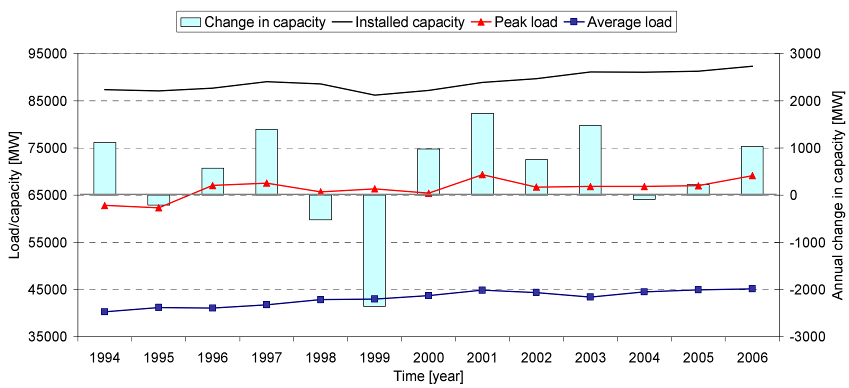

Figure 1
Installed Capacity, Peak and Average Load, and Annual Change in Installed Capacity (right hand axis) in the Nord Pool Market
Source: Nordel.

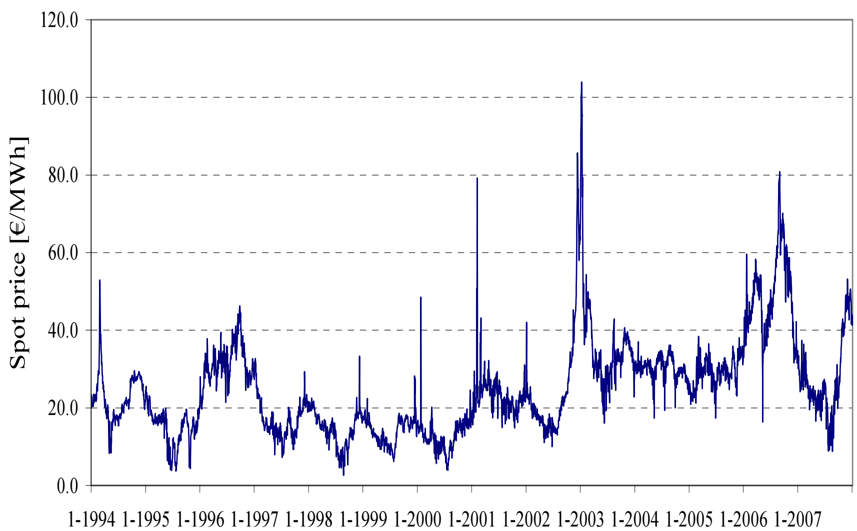

Figure 2
Average Daily Prices in Nord Pool Market, 1994-2007 in €/MWh
Source: Nord Pool.

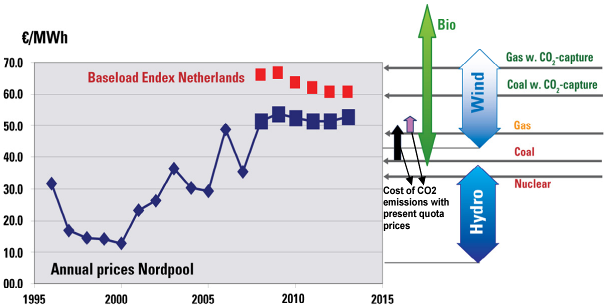

Figure 3
Nord Pool Market Prices (historical and futures prices) and Total Levelized Costs of New Generation
Source: SINTEF Energy Research, Norway.

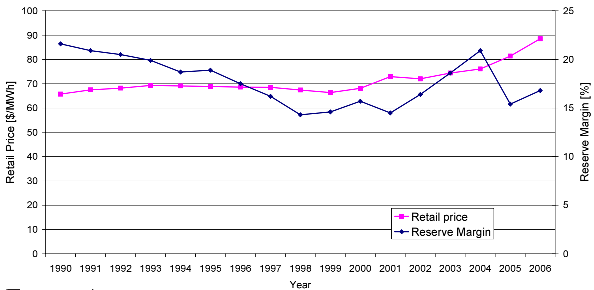

Figure 4
Development of Reserve Margin and Average Retail Electricity Price in the United States
Source: EIA.

dramatically given the initial surplus situation. Another relevant analysis is to compare the market prices with the cost of new generation. Figure 3 clearly shows that only hydro, nuclear and coal power are profitable with the price levels expected up to and beyond 2010. In line with this analysis, present investments are in small and medium sized hydro power (Norway) and nuclear power (Finland), as well as subsidized wind power in Denmark and Sweden.

Overall, investments in generation capacity do occur, partly on commercial conditions, partly based on subsidies for renewable power. However, the necessarily tighter balance will inevitably lead to periods with high prices that consumers must learn to cope with. Nord Pool has a fairly well developed retail market, where end-users can choose between contracts that follow the spot price and longer term contracts with a fixed price. Although consumers to some extent can hedge against price fluctuations through long-term contracts, most consumers still choose spot price related contracts and are, therefore, exposed to the short-term price variations.

United States

Over the last 10 years regional wholesale electricity markets have been established in some parts of the United States, mainly in the North East, California, Texas, and the Mid West. However, there are a number of states where the electric power industry is still basically operated as traditionally regulated monopolies.

Figure 4 shows that the overall reserve margin in the U.S. power system is much lower than in the Nord Pool system. A likely explanation is that hydropower makes up a much smaller fraction of the total generation capacity in the U.S. The reserve margin was falling during the 1990s. A low level of investments in new generation capacity, combined with a relatively high load growth (average growth in peak load was 2.1% from 1990 to 2006) explain the decrease. The reserve margin increased substantially from 2001 to 2004 due to a boom in generation investment in this period (Figure 5). A striking observation is that almost all the new generation capacity over the last 10 years has been gas-fired, mainly combined-cycle plants. Average retail prices remained almost constant during the 1990s, but have increased over the last years, probably due to higher fuel prices. There is no apparent link between the reserve margin and the retail price (Figure 4).

One should be careful in assessing capacity adequacy in U.S. electricity markets based on national figures, given the various states of restructuring in different parts of the country. Below we, therefore, provide some statistics from five of the regional wholesale electricity markets. Table 1 shows that the reserve margins are small in these markets, particularly in the New England and California markets. At the same time there is high growth in peak demand.

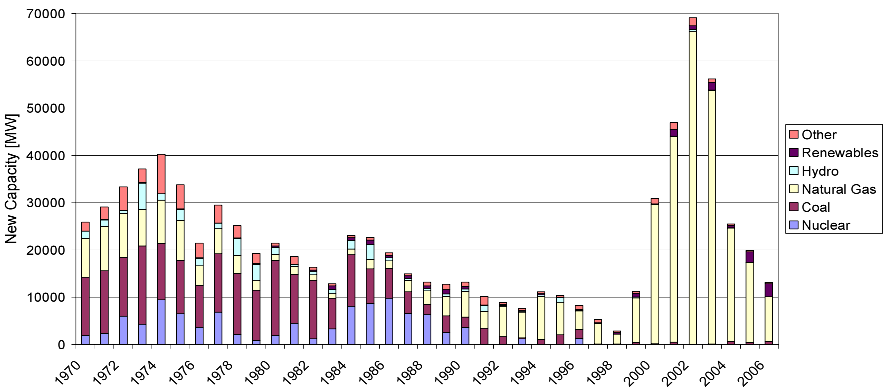

Figure 5
New Generation Capacity in the U.S. by Energy Source, 1970-2006
Source: EIA.

	PJM	ISO New England	New York ISO	ERCOT (Texas)	California ISO
Reserve margin	14 %	10 %	17 %	14 %	12 %
Peak load	8.1 %	4.6 %	5.6 %	3.5 %	10.7 %

Table 1
Reserve Margin (2006) and Peak Load Growth (2005-2006) in Five U.S. Wholesale Electricity Markets
Source: FERC.

	PJM[1]	ISO New England[2]	New York ISO[3]	ERCOT[4]	California ISO[5]
2004	41.73	53.72	63.16	42.63	46.84
2005	60.89	78.54	93.77	66.81	55.52
2006	50.07	60.94	70.90	51.98	39.64

[1]PJM Western Hub [2]Mass Hub [3]New York City Zone [4]ERCOT North Hub [5]SP-15

Table 2
Average Annual Prices in Five U.S. Wholesale Electricity Markets for Selected Hubs/Zones, 2004-2006
Source: FERC.

Table 2 shows the average annual prices in the same markets. The average prices can be compared to the US Energy Information Administration's current estimates of total levelized costs for new natural gas, coal, nuclear and wind generation, ranging from 55 $/MWh to 68 $/MWh (EIA 2007). With some exceptions, like the New York City Zone, the historical prices tend to be below the total cost of new power generation. In fact, several investors in new gas-fired generation capacity during the recent investment boom ended up going bankrupt.

Low reserve margins combined with what appears to be insufficient revenues from the energy market to recover new generation investments may explain why several U.S. markets (PJM, ISO New England, New York ISO) have capacity markets. In their original implementations, a fixed capacity obligation was determined for each load serving entity (LSE), according to the system reliability criterion and the LSE's share of total system demand. The capacity obligation was accompanied with a capacity market, where LSEs could purchase capacity in order to meet their obligations. However, these capacity markets are undergoing a number of modifications. An administratively determined capacity demand curve is now typically used to determine the capacity price, which also depends on the location in the network. At the same time, a longer forward procurement period is used to allow for new generation to compete in the capacity auctions (Crampton and Stoft 2006, Hobbs et al. 2007). California ISO is also considering introducing a capacity market, whereas the ERCOT market in Texas is basically an energy only market.

Looking Ahead

As the discussion above illustrates, there is no uniform solution for capacity adequacy in electricity markets. The choice of market design will depend on the conditions in the specific country or region, such as load growth, generation mix, amount of renewables, level of demand response, etc. Administrative capacity payments and capacity market constructs deviate from market-based solutions and involve significant transfer of wealth from consumers to producers. Consumer preferences are better represented in the proposed reliability options and capacity subscription schemes.

We believe that the long-term solution lies in increased demand participation in electricity markets, both in terms of short-term price response and increased participation in long-term markets. This will enable better scarcity pricing and more liquid and mature long-term markets for risk management. Over time, this should eliminate the need for specific capacity adequacy policies. A prerequisite for this development is that it becomes politically acceptable that consumers are exposed to varying and occasionally high prices.

Finally, since most electricity markets are still relatively young, the overall experience with generation investment and capacity adequacy policies is very limited. Modeling and simulation can, therefore, play an important role in testing different policies and designing robust electricity markets. Examples of recent simulation studies that address the long-run consequences of electricity market restructuring include De Vries (2004), Botterud et al. (2005, 2007), Kadoya et al. (2005), Hobbs et al. (2007), and Doorman et al. (2007).

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Student Awards at GEE, Germany

The German Chapter of the IAEE (Gesellschaft fuer Energiewissenschaft und Energiepolitik e.V. or GEE) regularly announces a Student Award for outstanding scientific works. In 2002 the first award has been assigned for a PhD thesis, since 2006 both the best diploma thesis and the best PhD thesis are awarded 750 € and 1,500 €, respectively.

During workshops – organized twice a year in spring and fall by the German Student Chapter – PhD Students as well as under-graduates can present papers, work in progress, diploma theses or PhD thesis. During the dialogue among these young researchers and with seniors from academics as well as practitioners a regular exchange can be held up and new ideas are discussed. Submitted works cover various empirical and theoretical aspects (e.g. regulation of network industries, corporate strategies in energy markets, supply security, global warming economics, carbon capture and storage, innovative technologies, etc.) and all energy related sectors (e.g. oil, natural gas, coal, renewables, electricity, etc.).

Based on the submissions for the fall-workshop, the three best works in both categories are selected by a committee of professors. These finalists compete during the workshop with their presentations and during the following discussion. The winners are announced during a dinner the same evening.

Sophia Ruester

GEE student members receiving awards in November 2007. Caroline Heidorn on the right for the best diploma thesis and Dr. Christoph Gatzen on the left for the best PhD thesis. Prof. Georg Erdmann (GEE President) and Sophia Ruester (Student Chapter – organizer of the GEE Student Workshops) are also shown.

Economics of Interconnection: the Case of the Northwest European Electricity Market

By Paul Giesbertz and Machiel Mulder*

Introduction

In order to create an internal European market for electricity, interconnection lines between several European countries are being developed. The Dutch market, now only directly connected to the German and Belgian market, will be linked to the Scandinavian and British market in 2008 and 2010, respectively. Economically, these investment projects raise several fascinating questions. As the costs of the investments amount to hundreds of millions of euros, while the benefits are fairly uncertain, the profitability is a key issue to be dealt with. This regards the efficiency on both business level and general level. Questions to be answered are: can the investments be financed from the business returns and, if not, are the investments profitable from a general economic (welfare) point of view? The answers to these questions are directly linked to the issue of the institutional organisation: should the responsibility for these investments be solely left to the public TSO or should privately owned firms be given the option to also be involved?

In this paper, we deal with these issues by discussing the economics of the investments projects which will link the Dutch market to the Scandinavian market (NorNed-cable) and to the British market (BritNed-cable). Regarding the NorNed-cable, we go into the overall welfare effects, while the institutional aspects is discussed referring to the BritNed-cable which is a (commercial) merchant cable. The respective questions which we answer are:

a. do the overall economic benefits of the NorNed-cable (likely) exceed the investment costs?
b. what is the added-value of the possibility of commercial investments in interconnection, such as the BritNed-cable?

Welfare Effects of Interconnection: the Case of NordNed[1]

In 2008 the Nordic and the Dutch power market will be connected through NordNed, a transmission cable between Norway and the Netherlands. This cable, developed by the Dutch and Norwegian transmission system operators (TenneT and Statnett, respectively), has a length of 580 kilometres and a capacity of 700 MW. The cable will be used to daily arbitrage between the markets in the two regions: if, for instance, the Dutch price is below the Norwegian price, electricity will be bought on the Dutch spot market (APX), which is already linked to the markets in Germany, Belgium and France, and sold on the spot market in Oslo, Nord Pool, which is the common Scandinavian power exchange, linking the markets of Denmark, Finland, Norway and Sweden.

How should we assess this interconnection, economically? In order to determine the overall economic effects, we use a cost-benefit framework. Compared to the benefits, the costs of the investments are rather clear. The costs mainly consist of the investments which have already been made. The investment costs are about 550 million euro. Future costs, consisting of annual maintenance costs, constitute a relatively minor part of total costs. These future annual costs are estimated at about 4 million euro.

The benefits of NorNed, however, are rather uncertain as these have to be realised in the (near and long term) future. Moreover, the benefits include several components which are difficult to monetarize. The main benefit will follow from price differences between the Scandinavian and Dutch regions, while other benefit items may derive from impacts on competition and security of supply.

Benefits from Price Differences

These benefits, logically, only occur if the power price differs between the two power markets. Price differences may result from different factors, in particular differences in generation techniques and in demand profile.

In the Nordic markets, electricity is mainly generated by hydro plants, while in the Netherlands gas-fired and coal-fired plants dominate the generation mix. Hence, the Dutch supply is highly sensitive to changes in fossil-fuel prices, while the Nordic supply strongly depends on the availability of water.[2] These large differences in generation techniques constitute a major source of price differences.

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See footnotes at end of text.

Moreover, Dutch supply is characterised by a fairly steep merit order (caused by the strong variation among power plants which have limited capacities), while the Nordic supply curve is rather flat (resulting from its fairly homogeneous generation method). Because of these characteristics, Dutch power prices are strongly related to the size of the demand, while Nordic prices can be rather stable in the short term, provided that the level of water reservoirs remains sufficient to meet (growing) demand.[3]

Finally, the demand profile of Dutch electricity users also differs from Nordic consumers. In the Netherlands, electricity is mainly used by non-residential users (such as large industrial users), while in Norway, residential use is relatively important (about one-third of total consumption), in particular in winters for heating purposes.[4] As a result, Dutch prices strongly vary between day and night, which offers opportunities to export during night time and import during daytime.

So, price differences between the Dutch and the Nordic markets form a potentially significant source of benefits of the interconnection. Acknowledge, however, that these benefits are not equal to the welfare effects, as they mainly consist of distribution effects. After all, transport of electricity from a low-price region to a high-price region raises prices in the former region and reduces them in the latter, affecting all power users in both regions.

The real welfare effect compromises both productive and allocative efficiency. The productive-efficiency effect follows from the increased efficiency of generation. The interconnection enables a more extensive use of the cheapest method of generation. If, for instance, (marginal) costs of producing electricity is high in the Netherlands compared to Norway, it is welfare enhancing to generate the (marginal) power in Norway in stead of in the Netherlands. The allocative efficiency benefit of the interconnection follows from the fact that the price level will get closer to the level of the marginal costs in both regions. Without interconnection, some consumers do not use power because the price they have to pay exceeds their willingness-to-pay while the latter exceeds the marginal costs. Note, however, that the relatively low price elasticity of demand implies that the allocative benefits of the interconnection will not be large.

Benefits from Enhanced Competition

In addition to the benefits following from price differences, benefits from enhanced competition may result from the interconnection. Competition in the Dutch power market is stagnating owing to the limited number of players.[5] In many hours one or more players are pivotal in meeting demand, although they are not necessarily always the same players. The high degree of concentration and the regular pivotality of one or more players have an impact on market outcomes: the greater the pivotality, the more the electricity price differs from the underlying costs of production.

If the available interconnection capacity increases, prompting other providers to enter the wholesale market, the current players will be pivotal to a lesser extent or less frequently. As a result, the wholesale price (particularly during peak and super-peak hours) will decrease. Due to the competition in the end user market, this price benefit will be largely passed on to the consumer. Consumers will also benefit indirectly, since lower electricity prices will be reflected in lower product prices.

These benefits mainly comprise distribution effects, as they are the result of a transfer from producers to consumers. In addition, enhanced competition will likely result in some benefits for productive efficiency, owing to an increased dispatch efficiency, and for allocative efficiency, because of less distorted prices.

Benefits from Increased Security of Supply

Another benefit from the interconnection is that the security of supply can be realised against lower costs. In an isolated market, more installed generation capacity is needed than in larger markets. Due to the NorNed-cable, the Norwegian hydro storage capacity can be lowered, just as the Dutch can reduce the size of the installed generation capacity necessary to meet peak demand. In both regions, market forces will take care of these effects. As the interconnection will reduce the volatility of prices in both regions, the efficiency of capacity which is hardly used will decline. In the long term, this will result in a lower level of installed capacity.

Overall Economic Assessment

Investments in interconnection do not automatically generate positive welfare effects, as the upfront costs are significant while the benefits are fairly uncertain. Regarding the NodNed-cable, the Dutch energy regulator concluded that the overall economic effect will be slightly positive, although benefits from enhanced competition and the benefits for security of supply were not monetarised.[6] Inclusion of these benefits in the cost-benefit analyse results in an investment project which seems to be beneficial. The future will teach us whether this expected efficiency will be realised or not.

Merchant Lines Within a Public Network: the Case of BritNed[7]

In 2010 the British and the Dutch power market will be connected through BritNed. This DC transmission cable is developed by a joint venture of the British and Dutch TSO (National Grid Company and TenneT, respectively). This cable will have a length of 250 kilometres and a capacity of 1000 MW. This cable will be used as a merchant cable. How should we assess such a commercial investment within the publicly owned transmission network?

European Regulatory Framework

The regulatory framework in the European Union allows for merchant investments in transmission provided a set of conditions is met. The European approach is laid down in the EU Regulation on Cross-border Exchanges which entered into force July 1, 2004. This regulation allows for new interconnectors to be exempted from rules that regulate the revenues of allocation of scarce interconnector capacity and from rules that require (regulated) third party access to the network.

The exemptions can only be granted under the following conditions:

- the merchant interconnector should enhance competition in electricity supply;
- the level of the risk is such that the investment would not take place unless the exemption is granted;
- the interconnector must be owned by a person legally separate from the TSOs (so no full ownership unbundling is required);
- charges must be levied on users of the interconnector;
- since the start of the European electricity liberalisation, no part of the capital or operating costs of the interconnector has been recovered from any component of the network tariffs;
- the exemption is not to the detriment of competition or the effective functioning of the internal electricity market or the efficient functioning of the regulated systems to which the interconnector is linked.

Opening interconnection investment to private parties has not yet led to a significant increase in power transmission investment projects. Only two merchant investments in power transmission have been granted exemption in Europe (the Estlink and the BritNed interconnectors). Moreover, in both cases TSO holding companies are the investing companies, so that the two projects are nor real merchant projects.[8] Below, we discuss a number of pros and cons often attributed to merchant lines.

Compensating for Lack of Regional Coordination

It has been argued that the possibility of merchant investments is necessary as in case of regulated investments the authorities at the side of the low-price market might be reluctant to increase the transmission capacity, since that investment would raise the local power price. Merchant investors might compensate for the lack of coordination between national authorities and TSO.

This argument has been weakened by the recent legislative proposals of the European Commission concerning the electricity and gas market (the 3rd Package). The Commission proposes, among others, to establish an Agency for the cooperation of energy regulators (hereafter: Agency). This Agency would complement at European level the regulatory tasks performed at national level by the regulatory authorities. One of the proposed tasks of the Agency is the granting of exemptions from third party access rules where the infrastructure concerned is located in the territory of more than one Member State. By bringing the authority for granting exemptions at a EU level, the above argument in favour for merchant investments has disappeared.

Suboptimal Decisions of TSO

Another argument in favour of merchant investments is the perceived problem of under-investments in case of vertically integrated utilities. Such a utility might have the incentive not to invest in cross-border capacity in order to protect its generation activities in its own market. Also this second argument would disappear with the implementation of the new EU energy package as ownership unbundling of TSOs is a core element (and also the most criticized element) of the package.

Suboptimal Decisions of Regulators and Regulatory Uncertainty

Suboptimal behaviour can also be caused by lack of (political) willingness to allow regulated investments in certain transmission lines although they would be socially optimal. Despite the social benefits, the consequence normally is that regulated transmission tariffs will have to be increased.[9] Such behaviour might happen especially in cases of several investment projects being proposed.

Regulatory uncertainty might also hamper investments in regulated lines. The TSO faces the risk that a regulator might change the rules after the investment has been done. This might lead to under-investments especially in case of large investments.[10]

Both arguments are not of fundamental nature. However, it can be not denied that these arguments can become relevant in practice.

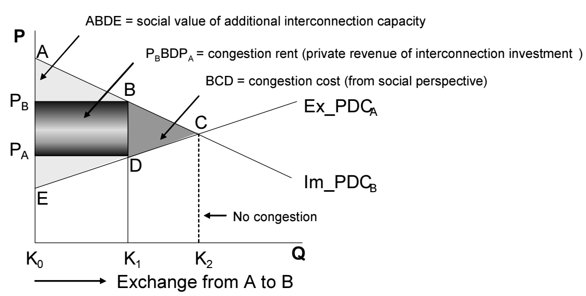
Private Investors are Said to be More Efficient

The last and more fundamental argument to allow for merchant investments is that a private investor has stronger incentives to produce efficiently. This incentive is normally less strong for (publicly owned) TSOs in case of regulated investments, although it depends on the regulatory approach. In the case of the NorNed-cable the Dutch regulator has included several incentives in its decision to allow for the investment. Incentives are placed on the total project cost, the timely delivery of the project and the capacity and availability of the cable. It is too early to assess whether these incentives have proved to work. Theoretically, however, these attempts to increase incentives on TSOs (and to shift the risk for consumers towards TSOs) will never be perfect.

Argument Against Merchant Lines

The above might lead to the suggestion that the possibility to allow for merchant investments in power transmission is not necessary. Two main arguments would disappear with the implementation of the 3rd EU legislative package. Two more arguments would not apply in case of proper regulatory approaches. And the last and more fundamental argument could be weakened if innovative regulatory incentive schemes could be implemented. However, the question could also be turned around. Why should we not allow for the possibility of merchant investments? Two arguments against merchant lines should be mentioned.

Network externalities may arise, as the use of the line cause loop flows in other parts of the network. These loop flows affect the efficiency of other parts of the network, but they are not taken into account by the merchant investor.



Another argument against merchant lines is that merchant investors have the incentive to maintain bottlenecks in order to keep price differences. As a result, the capacity of a merchant line is likely below the socially optimal level. This is illustrated in the adjacent figure.[11] The horizontal axis represents the interconnection capacity between two nodes A and B, whereas the vertical axis gives the price in each node. A merchant investor will try to maximise the congestion rents, represented by $P_B BDP_A$, whereas the total social value of additional interconnector capacity is represented by ABDE.

These two arguments become even more important in cases where the TSO is involved in the merchant project (which is the case for both BritNed and Estlink). The TSO might have an incentive to operate the system with the objective to maximise the revenues of the merchant project.

Conclusion

Extending the interconnections between countries enlarges the market which potentially increases the productive efficiency of power generation, enhances competition and improves security of supply. The interconnection between the Nordic and Dutch market by NorNed as from 2008 will produce these benefits, which will likely exceed the costs of developing and maintaining the interconnection. Nevertheless, uncertainty about the efficiency remains. Generally, cost-effective alternatives for physical extension are enlarging the availability of already existing lines and improving the possibilities for effective cross-border trade (e.g. by creating options for cross-border intraday trade). Moreover, it is important to note that even in well connected regions, transmission costs remain. In many cases, investments in new power plants within a region will be a cost-effective alternative for developing or extending interconnection lines. So we stress the importance of systematically analysing the costs and benefits before making the final investment decision on interconnection.

Merchant interconnection lines may have an added value, but this value will likely be reduced by the new proposals of the European Commission. The 3rd legislative package of the EC aims to tackle the market integration process, in which interconnections play a key role, by ownership unbundling of TSOs and establishing stronger and independent regulatory authorities. Regional cooperation is then facilitated by an Agency and a European Network of TSOs. This approach should provide a better framework for regulated investments in transmission projects and, therefore, reduces the need for merchant lines. The possibility of merchant investments is still left open, which is important as the merchant option has several advantages. Special attention, however, should be paid to the risk of strategic behaviour by TSOs if TSOs are involved in the merchant project.

Footnotes

1 See also Carel van der Lippe en Paul Meijer, De NorNed-kabel: een gereguleerde investering met betekenis voor de markt, Tijdschrift voor Politieke Ekonomie, 2005(27)2, pp. 79-92, and: Michiel de Nooij, Leren van NorNed, ESB, 13 juli 2007, pp. 429-431.
2 Energy Systems Analysis (ESA), Background study – Balancing system of Denmark, 2004.
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4 Source: www.iea.org.
5 NMa-DTe, Market Monitor: Development of the Wholesale Electricity Market in 2006, The Hague, 2007.
6 DTe, Besluit op de aanvraag van TenneT tot het toestaan van de financiering van de NorNed-kabel op grond artikel 31, zesdelide van de Elektriciteitswet 1998, besluit 101783-2-76.
7 See also G. Brunekreeft en H.M. Godfried, Netverbindingen door markt, ESB, 19 maart 2004.
8 See also Rudi A. Hakvoort and Hanneke M. de Jong Pushing European power transmission: Private investment in priority interconnections?, EREM, 2007
9 See also Rudi A. Hakvoort and Hanneke M. de Jong Pushing European power transmission: Private investment in priority interconnections?, EREM, 2007
10 See also G. Brunekreeft and H.M. Godfried, Netverbindingen door markt, ESB, 19 maart 2004 (in Dutch)
11 See Rudi A. Hakvoort and Hanneke M. de Jong Pushing European power transmission: Private investment in priority interconnections?, EREM, 2007

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Generation, Transmission, and the Load Pocket Problem

By Richard Benjamin*

Introduction

Restructured electricity markets present several problems not present in traditional electricity markets. Particularly thorny is the question of how to efficiently manage load pockets. In traditional electricity markets, vertically integrated firms internalize this problem, choosing the mix of generating and transmission assets, subject to state commission planning review. In a restructured electricity market, price signals would ideally do the job.[1] However, as load pockets become sufficiently small, maintaining enough generation plus transmission capacity to support a competitive market becomes prohibitively inefficient. In absence of competitive prices signaling the need for transmission and generation expansion, the regulator must design a framework in which these decisions are made. This paper examines the regulator's problem in developing such a framework. The first section reviews the methods PJM, ISO-NE, and California use to manage load pockets, and their attendant incentives for transmission and generation expansion. The second section discusses frictions facing individual load-pocket generation and transmission projects. The third addresses issues considered in evaluating the desirability of generation versus transmission in alleviating load-pocket congestion. The fourth section proposes an alternative means to mitigating load-pocket market power problems and for providing incentives for generation and transmission in load pockets. The fifth concludes.

RTO Load-Pocket Practices

FERC's Order on the CAISO's Market Redesign and Technology Upgrade (MRTU)[2] mitigates generation market power through incrementally increasing caps on suppliers' bids into the CAISO's real-time markets. At MRTU's effective date, the real-time bid cap will be $500, rising to $1,000 over a period of two years. With respect to load pockets, the CAISO conducts an annual assessment of all transmission paths, finding them to be either "competitive" or "non-competitive."[3] It uses this assessment to determine units subject to local market power mitigation. Those units whose dispatch level increases from a dispatch algorithm run taking into account only constraints over "competitive" transmission paths to a run incorporating all constraints in the Full Network Model are subject to the CAISO's local market power mitigation measures.[4]

Both the CAISO and the CPUC play roles in ensuring adequate supply of power in load pockets. The CPUC exercises its constitutional authority over resource adequacy by requiring California's investor-owned utilities to file their long-term procurement plans before the CPUC. The CPUC has also instituted a resource adequacy requirements program to ensure adequate resources are available.[5] The CAISO mitigates load-pocket market power while ensuring load-pocket adequacy by awarding one-year reliability-must-run (RMR) contracts to generation needed for reliability within load pockets.[6]

PJM also calls on units to run for reliability purposes. PJM determines which units to call based on facility outages or other system conditions which may give rise to a transmission constraint, requiring the facility's operation to maintain reliability.[7] With certain exceptions, PJM places caps on the offer prices of any generation resources dispatched out of economic (merit) order to maintain reliability. The level of these offer caps depends on the frequency with which PJM caps the unit. The offer cap increases with the frequency with which the unit is capped. [8]

PJM uses scarcity pricing as well as must-run designations in dealing with load pockets. While must-run and offer capping ensure reliable service at reasonable prices, scarcity pricing signals the need for generation and transmission additions. When load in a PJM scarcity pricing region[9] gets high enough to trigger a scarcity condition, PJM implements scarcity pricing. When a scarcity condition exists inside of a scarcity pricing region, PJM determines the locational marginal price (LMP) at all nodes in a scarcity pricing region based on the highest market-based offer price of all units operating according to PJM's directions to supply either energy or reserves on a real-time dispatch basis. Generation operating under scarcity pricing is subject only to PJM's maximum offer cap of $1,000/MWh. PJM uses its regional transmission expansion planning protocol to decide on transmission projects to improve grid configuration, and locational capacity pricing in capacity markets to signal the need for generation in load pockets.[10]

ISO-NE names geographic areas in which it regularly calls on resources owned by a limited number of suppliers to relieve transmission constraints as

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See footnotes at end of text.

Designated Congestion Areas (DCAs). ISO-NE then negotiates reliability agreements with those resources whose operation it deems necessary to maintain reliability within the DCA.[11] It mitigates these units by compensating them with the greater of the applicable LMP, a cost-based rate, or the lower of their supply offer or the applicable reference level when it calls on them for reliability purposes. ISO-NE uses zonal capacity requirements and locational reserve requirements for reserve zones to provide the incentive for generation expansion for local reliability purposes.[12] ISO-NE's Regional System Plan evaluates the efficacy of different resources (e.g., generation, distributed generation, transmission, and demand-side projects) in determining the optimal load-pocket expansion strategy.[13]

Frictions Facing Load-Pocket Resource Additions

Load pockets invariably comprise densely-populated regions, often involving geographically isolated areas. Generation construction in these areas typically faces strong resistance (the not-in-my-backyard, or NIMBY effect), due to health, environmental, and aesthetic concerns. In San Francisco, for example, both the abandoned Potrero Unit 7, which Mirant abandoned when it faced bankruptcy, and the San Francisco Electric Reliability Project have faced stiff opposition.[14] Thus politics may be more important than efficiency concerns in siting load-pocket generation.

RTOs' load-pocket market power mitigation measures may also frustrate efforts to build new generation. Chao et al. (2005) maintain that low price caps, combined with centralized unit commitment by RTOs, which depresses the price for offline reserve capacity, give insufficient revenues to support new combustion turbines.[15] Lave et al. (2004) contend that the uniform price auction overpays baseload generation during peak periods while simultaneously discouraging new investment. They state that because high-cost peaking units would receive only their marginal cost of generation in a competitive market, investors in new units would have to be offered an incentive equal to fixed costs to induce them to build.[16]

Adding transmission to alleviate load pockets is also problematic. Overhead lines are a "non-starter" in heavily-populated areas, and even underground lines face opposition. Several community groups vociferously opposed the Jefferson-Martin line,[17] raising issues with respect to both the overhead and underground segments. Among the complaints regarding proposed routes for the underground section of the line were that it ran through residential neighborhoods, past schools, by professional and medical office buildings, and presented unacceptable construction impacts such as noise, traffic, emergency access and business losses, and would entail residential EMF exposure.[18] Many economists also argue that financial transmission rights (FTRs) create an underincentive for grid expansion because new investment in transmission diminishes the value of existing FTRs.[19]

Coordinating Generation and Transmission Additions

Not only does individually building generation or transmission individually in load pockets present problems. An equally daunting task is how to arrive at the right mix of the two assets. This problem has both spatial and temporal dimensions. Spatially, the loss of vertical integration of utility planning leaves entities with differing incentives making uncoordinated locational investment decisions. Chao et al. (2005) argue that generation builders prefer to locate in load pockets (due to high prices there). He concludes that regulators must step in because transmission expansion may be more efficient.[20]

A central temporal problem arising in transmission siting decisions is that transmission takes much longer to build than generation. According to Joskow and Tirole (2003), this allows a generation investor to strategically preempt a competing transmission project, even if the transmission project is more socially valuable.[21] Brennan (2006) thus reasons that "efficient transmission investment and competitive generation requires the design and solution of a multistage game among the transmission provider and generators that can choose to build earlier or later."[22] He is, therefore, skeptical regarding the prospects for adequate transmission investment in restructured markets.

The other major temporal consideration is the long life spans of both generation and transmission. Chao et al. (2005) note that private generation investments depend on the supporting transmission infrastructure. Because LMPs depend on grid topology, the profitability of generation is subject to future transmission investment decisions. Thus, private generation investors need reliable forecasts of grid topology in order to make informed decisions on where to locate new plants.[23] Calviou et al. (2004) concur that deciding on the optimal generation/transmission mix is a complicated by the long planning horizon necessitated by the long lives of the assets.[24]

Determining the optimal generation-transmission mix requires consideration of various factors. Pratt (2003) argues that transmission enhancements ought not to be favored over other solutions, but that planning authorities should compare transmission enhancements or expansions against market proposals such as generation, merchant transmission, and demand response. He argues that transmission planning rules should be designed to select the most efficient and cost-effective solutions.[25] Calviou et al. (2004) add that in comparing transmission and generation, one should recognize that transmission reduces the market power of load-pocket generators more effectively than new generation. The authors argue that load pockets are analogous to protected markets. They reason that a new generator in a load pocket simply competes for marginal demand against the least efficient unit, but that an increase in transmission is tantamount to a reduction in trade barriers.[26]

Alternative Regulatory Mechanisms for Load Pockets

Lave et al. (2004) conjecture that the cost of additional generation and transmission needed to support a competitive market might be so great as to render competitive electricity markets inefficient.[27] No where is this hypothesis more true than in geographically isolated population centers like San Francisco, with a peak load of approximately 2,000 megawatts. The basic problem is that economies of scale render competition in small markets inefficient, especially in electricity where hourly auctions, with even a moderate number of participants, facilitate tacit collusion[28] and local generation is needed for voltage support. Therefore, mitigation in load pockets seems inevitable.

The question is what approach regulation should take in this case. I would argue that restructuring has put the cart before the horse here. Before opening up transmission-constrained population centers to competition, one ought to have an "end game" in mind. If that end game is just mitigation, then one should think carefully before prescribing competition in these areas. The basic problem is that in the face of inelastic demand, an imperfectly competitive firm's profit-maximizing strategy is to raise prices. This is antithetical to the mandate that FERC ensure that wholesale electricity prices are just and reasonable.

The question then becomes whether continuation of VIU operation in load pockets would have been a more efficient option than mitigation of merchant generation. More formally, this alternative would have entailed VIUs retaining all load-pocket generation. This generation would then receive its marginal cost in the wholesale electricity market, with fixed costs recovery in retail rates. The generator would be free to bid into any markets in which it had market-based rate authority.

I believe continued VIU operation in load pockets would be preferable to restructuring in load pockets for a few reasons. The first is the problem of incentives. Because demand for electricity is generally quite inelastic, generation owners can be expected to withhold generation either physically or economically, provided the probability of detection is low enough. Even in PJM, which mitigates bids in load pockets, generators still receive the LMP (based on their mitigated bids). Thus physical withholding might still be profitable. The VIU does not have the same incentive. Since the generator earns only marginal cost in the wholesale market, it has no incentive to block rival generation coming into the load pocket by withholding transmission. Further, it has the incentive to run its generation whenever doing so is the least-cost strategy, because its retail rates are fixed in the short run.

The second reason is the start-up cost associated with adopting a new regulatory regime. In the case of U.S. electricity restructuring, this involved the incremental time spent training Office of Enforcement personnel This involves the marginal time required to train personnel with regard on load-pocket issues, as well as losses from imperfect detection of market manipulation in load pockets as employees are still learning their jobs.

In order to justify these costs, the regulator must find at least commensurate benefits. In hindsight, these benefits have not been realized. In the short term, load pocket mitigation in restructured markets cannot be any more efficient than cost-of-service regulation. In fact, it will have been less so, if load pocket generators have been able to practice physical or economic withholding. In the long run, whether restructured markets or VIUs will bring more efficient load-pocket expansion is an open issue. PJM and ISO-NE have gone through multiple policy revisions in trying to give merchant generators the incentive to locate in load pockets. As merchant transmission may loosen up load-pocket constraints regardless of the competitive structure inside the load pocket, it is not an issue.

Let us repeat that even if the benefits of load-pocket restructuring are not sufficient to justify its implementation, we need not conclude that we are stuck in the pre-Order 888 world where VIUs use transmission constraints to starve their competitors' access to customers. Provided that the VIU generation earns only marginal cost in the load pocket, it has no reason to discriminate in the short run. The regulator's chief concern is then attaining long-run efficiency. Once again, we are faced with the Averch-Johnson effect. In addition to Averch-Johnson, though, the introduction of FTRs/auction revenue rights (ARRs) creates an additional incentive for inefficient utility operations.

To illustrate this effect, I consider a simplified load-pocket example. Denote by K the amount of transmission capacity coming into a load pocket over a single transmission line, so as to ignore loop flow. In the load pocket there are two generators, A and B, both owned and operated by the incumbent utility. A and B are assumed to have fixed marginal costs of generation, with $MC_A < MC_B$. That is, B is the older, less efficient, and thus more polluting plant. As described above, load-pocket generators would receive their variable costs in the wholesale energy market. Denote the relevant portions of the supply curves for imports, generator A, and generator B by S_I, S_A, and S_B, respectively. Assume further that load pocket demand is perfectly inelastic at quantity Q_L, and that B has excess capacity at this load, so that the LMP (for purposes of calculating FTR revenues) is P_L. In this case, imports supply quantity K at price P_I, generator A supplies quantity $(Q_2 – K)$, and receives its marginal cost, equal to P_A. Generator B supplies quantity $(Q_L - Q_2)$ at its marginal cost, P_L. Graphically, see Figure 1.

Now consider the VIU's decision as to whether to keep the old plant running or shut it down and replace it with an equivalent amount of new generation or transmission capacity.[29] If the utility builds new generation, its profit increases by the difference in the return to capital of the two plants. Since the old plant will be highly depreciated, this favors building.[30] Society is better off provided that the social benefit from building the new unit (that is, the change in redispatch cost, equal to the area Z in Figure 1) is greater than the cost of the new plant.

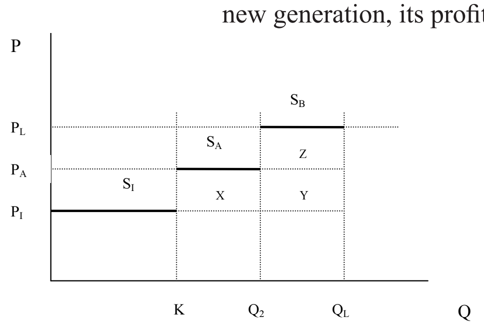

Figure 1
A Simplified Load Pocket Example

However, if it does build the new generator,[31] the load-pocket LMP falls from P_L to P_A, and thus FTR revenue falls from $(P_L – P_I)K$ to $(P_A – P_I)K$, as illustrated in Figure 2.

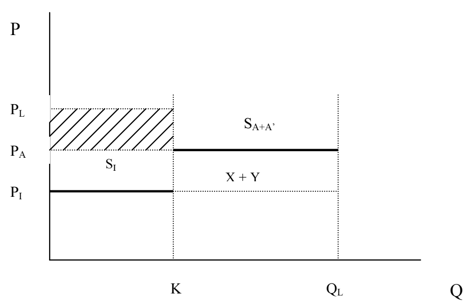

Figure 2
Adding Generation to the Load Pocket Reduces FTR Revenues

This loss in revenue will decrease, and possibly negate, the profit incentive to building new generation in the load pocket. Even worse, the less efficient the old plant, the greater the FTR revenue loss, and the greater the disincentive to replace it. Thus the relevant authority, be it the RTO or the regulator, should disallow any FTR collection in the load pocket beyond the amount $(P_A – P_I)$.[32] In order to align private and social benefit even better, the regulator should instruct the RTO to rebate a certain amount of money back to the VIU, as profit, after the latter builds the new plant. The primary reason for doing so is the social benefit from the improved health of local residents upon replacement of the old plant (providing that new pollution sources are not allowed to move in). The regulator might dictate that any remaining revenue be rebated to the utility's customers outside of the load pocket. This would decrease the amount by which these customers subsidize load-pocket energy consumption.

Now let us examine the utility's choice between building new generation, as above, or increasing transmission capacity into the load pocket. Increasesd transmission into the load pocket will allow more imports, with marginal cost P_I, into the load pocket. The social benefit from the new transmission is, again, the change in redispatch costs, equal to the area X+Z in Figure 1 (plus improved health due to the reduction in pollution). The social cost is equal to the private cost of the new transmission line, any health change due to EMF exposure, and decreased visual aesthetics associated with any overhead portions of the line. In this static example, transmission would be the optimal choice if the difference in redispatch cost savings between new generation and transmission (X) is greater than the difference between the levelized costs of transmission and generation (plus any difference in health effects).

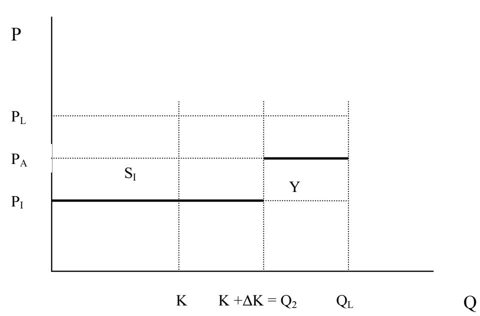

Figure 3
Adding Transmission to the Load Pocket

The good news in this example is that the regulator need no longer worry about the VIU turning down transmission expansion in order to disadvantage rival generation. As long as the utility's load-pocket generation receives marginal cost alone, the utility will be indifferent to how much it runs, ceteris paribus. All else is not constant, however, because in the short run, the utility's retail rates are fixed. This means that the utility will always strive for least-cost operation in the short run. It will thus want its load pocket generation to run whenever doing so is the least- cost (and thus, ignoring pollution) solution. This is why the VIU model, unlike the merchant generation model, gives the socially optimal incentives in the short run.

Turning back to the choice of generation and transmission expansion in the long run, the regulator still needs to be concerned regarding the incentive of the utility to choose the most costly alternative. This is so because the greater the cost, the greater the allowed return on investment. Thus the regulator is still in the business of approving utility resource plans in load pockets. The regulator's work is simplified by the restructured environment, however. Upon receiving the RTO's determination of resource need,[33] the regulator may require the utility to issue a Request-For-Proposals (RFP) for new generation. This RFP could include the utility's self-build option, along with proposals from other parties who would build the generation and then sell it to the utility. The utility would concurrently submit a transmission option. The RTO would then decide on which addition to adopt, severely limiting the ability of the VIU to "gold-plate" its portfolio.

Conclusion

Restructured electricity markets present several problems not present in traditional markets. An important issue glossed over in the restructuring process is whether or not the VIU model is the more appropriate alternative for load-pocket management. This paper has argued that this is the case. In the short run, the incentives of the VIU are better aligned with the goal of attaining power at a just-and-reasonable rate than those of merchant generators, whose incentive is to raise the price of power as high as possible in the face of inelastic demand. As RTOs, such as PJM, or PUCs, such as the CPUC already do resource planning, either model is amenable to long-run decision making regarding the choice of generation or transmission additions to meet load growth and replace old, inefficient plants. With little difference in the long-run mechanics of the two models, the improved short-run incentives of the VIU model argue for its adoption in load pockets.

Footnotes

[1] See, e.g., Keller and Wild (2004). Keller and Wild suggest that in traditional electricity markets, vertically integrated utilities chose transmission and generation to minimize total costs, but the Averch-Johnson effect (Averch and Johnson, 1962) suggests gold-plating by utilities. See, also Brennan, (2006).

[2] 116 FERC ¶ 61,274.

[3] The CAISO designates a transmission constraint as competitive if no three unaffiliated suppliers are jointly pivotal in relieving congestion on that constraint.

[4] These units are paid according to the generator's default energy bid, as explained in MRTU Tariff sections 39.7.1.1 – 39.7.1.4., http://www.caiso.com/17ba/17ba873e19350.html.

[5] See http://www.cpuc.ca.gov/PUC/hottopics/1Energy/R0404003.htm for details.

[6] Generators may choose between a contract that pays a certain percentage of the generator's annual fixed costs while allowing the generator to participate in the energy market, and a contract that pays the unit 100 percent of its fixed costs, but prohibits that unit from participating in market transactions expect under certain circumstances. Bids of RMR units are subject to mitigation (See MRTU Tariff, Section 31.2.2.1). The CAISO has also proposed a scarcity pricing mechanism.

[7] A PJM member that owns or leases local transmission facilities may, as long as it satisfies certain prerequisites, request that the Office of Interconnection dispatch generation in order to maintain local reliability (See Operating Agreement of PJM Interconnection, LLC, (PJM OA) section 6.3). http://www.pjm.com/documents/agreements.html.

[8] See PJM OA, sections 6.4.1. – 6.5.

[9] *i.e.,* load pocket. PJM OA sections 6A – 6A.3 describes PJM's scarcity mechanisms.

[10] See Manual M-18, PJM Capacity Market, at http://www.pjm.com/contributions/pjm-manuals/manuals.html.

[11] See ISO-NE Transmission, Markets & Services Tariff (ISO Tariff), sections III.6.2 and III.A.2.

[12] Id. sections III.9.2.3 and III.12.2. http://www.iso-ne.com/regulatory/tariff/index.html.

[13] See http://www.iso-ne.com/trans/rsp/index.html.

[14] See, e.g., http://www.sfgov.org/site/pppcatf_page.asp?id=18364 www.indiabasin.org/Action_Alert_Potrero.pdf

http://66.35.240.8/cgi-bin/article/article?f=/c/a/2007/10/23/EDVVSU8BI.DTL

http://www.californiachronicle.com/articles/viewArticle.asp?articleID=38469

It is interesting to note that in building the latter project, the City of San Francisco hopes to force the older, dirtier Potrero units out of the market.

[15] Chao et al. (2005) pp. 58-59.

[16] Lave et al. (2004) pp. 17-18.

[17] For a summary of protests, see CPUC Decision 04-08-046, at http://docs.cpuc.ca.gov/published/FINAL_DECISION/39122.htm.

[18] Id., p. 56.

[19] See, e.g., Brennan (2006), Bushnell (1999), Calviou et al. (2004), Joskow and Tirole, (2005), and Leautier (2001).

[20] Chao et al. (2005), p. 52.

[21] Joskow and Tirole (2003), p. 56.

[22] Brennan (2006), p. 43.

[23] Chao et al. (2005), p. 52.

[24] Calviou et al. (2004), p. 9.

[25] Pratt (2003), p. 69.

[26] Calviou et al. (2004) pp. 8-9.

[27] Lave et al. (2004), p. 17.

[28] See, e.g., Blumsack et al. (2006), pp. 18-19.

[29] More generally, the utility will choose between generation and transmission additions to meet peak-load growth in load pockets.

[30] Of course, the utility's building a new generator opens up its rate base to revision. In order not to provide an additional disincentive to building, the regulator should evaluate only the rate change induced by the new plant. .

[31] For sake of simplicity, assume the new generator has the same marginal cost as generator A.

[32] More generally, the RTO would compute FTR revenue in the load pocket based on a hypothetical dispatch assuming generation from A were the marginal load-pocket generation source.

[33] In the case of California, the CPUC has assumed this responsibility.

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The Parlous Investment Environment for Australian Electricity Generation and Transmission

By Lynne Chester*

Introduction

The 1990s delivered a decade of structural change, with astonishing rapidity, to electricity sectors around the world. Australia's electricity restructuring has been hailed by the International Energy Agency (IEA) as a role model against which other countries should benchmark their own progress. A core feature of this restructuring has been to place far greater reliance on the market to determine pricing and investment outcomes. This article explores the prospects for market provision of sufficient investment to provide the generation and transmission capacity needed to meet forecast electricity demand.

Today's Electricity Sector

The Australian electricity sector which existed in the early 1990s is unrecognisable today. Mimicking the changes initiated by the England-Wales sector and subsequently adopted by other international electricity sectors, the functions of generation and retail are exposed to competition and the natural monopoly functions of transmission and distribution are regulated to support competition. Electricity companies have generally become single function operations although, like elsewhere internationally, there is increasing re-integration of generation and retail activities. The vast majority of electricity generated and consumed in Australia is traded through the mandatory wholesale National Electricity Market (NEM) which commenced in late 1998.[1]

Thirty-four government electricity companies existed in 1990. By December 2007, the NEM had 126 registered participants compared to 77 when the market commenced some nine years earlier (NEMMCO, 1999, 2007c). However, the sector is dominated by government-owned companies de-integrated from former State government monopolies.

Across the NEM, private ownership currently accounts for around 30% of generation and transmission capacities respectively, 52% of services to distribution customers and more than 60% of services to retail customers (Chester, 2007). Offshore transnationals dominate private ownership just like other electricity sectors around the world and ownership changes are an ongoing feature.[2]

Retail competition has been progressively introduced, regulation has been increasingly transferred from State governments to Federal authorities and, like the UK and European Union, the regulation of electricity and gas is being merged.

Two features of today's Australian electricity sector, however, make it stand apart from its international counterparts. It is the only electricity sector to introduce and maintain a mandatory wholesale market.[3] Secondly, there has been no change to the key policy instruments used to transform the sector such as de-integration, privatisation, the creation of a mandatory wholesale market, retail competition, and regulation of transmission and distribution.

The Current State of Generation Capacity

Since 1990-91, when electricity restructuring was first mooted in Australia, total electricity consumption has increased by more than 50% and is forecast to grow by more than 60% from 2006 to 2030. A similar increase in generation capacity is needed to meet this expected growth (ESAA, 2003, 2007; Syed, Wilson et al, 2007).

Different types of electricity demand are growing at different rates. Peak demand, defined as periods of very high or very low temperatures resulting in the use of air-conditioning or heating, is growing at a much faster rate than average demand, the level of demand which occurs most of the time.[4] For example, 10% of the State of New South Wales' (NSW) generating capacity is being used for only 1% (or 87 hours) of total demand each year (NSW Government, 2004: 10). Consequently, the additional generation capacity needed to meet forecast demand needs to comprise both base-load and peaking plant capacity.

The NEM's operator, the National Electricity Market Management Company (NEMMCO), each year releases 10-year projections of the adequacy of generation plants and transmission networks to meet projected demand. The most recent projections, assuming a scenario of extreme temperature conditions, indicate a high probability of electricity supply interruptions for the State of Queensland by the summer of 2009-10, and a similar situation the following summer in Victoria and South Australia followed by NSW in 2013-14 if there is no additional generation ca-

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See footnotes at end of text.

pacity to that already committed (NEMMCO, 2007a).[5]

Installed generation capacity across Australia is nearly 45,000 MW - of which 91% was within the NEM - and IPPs provided a further 5,170MW of capacity (ESAA, 2007). The three eastern states of NSW, Queensland and Victoria collectively account for 85% of the NEM's capacity.

Installed capacity within the NEM has increased by 14% (5,113MW) since the mandatory wholesale market's commencement in 1998, but 98% of this increase occurred during 1998-2002. Moreover, nearly two-thirds of this increase was in Queensland with a further 22% in South Australia. Peaking plants dominated the increase, with additional base-load capacity essentially being minor augmentation to existing plants (ESAA, 2003; IEA, 2003). Coal provides about 80% of the fuel used to generate Australian electricity although gas-fuelled generation has dominated additions to capacity in recent years.

Table 1 shows intended and actual new NEM generation capacity for each year from 2000 to 2006. It is immediately apparent that only a small proportion of that proposed has reached construction stage. The lead times between construction and commissioning are also readily apparent.

The vast majority of generation capacity currently under construction is expected to be commissioned by 2008-09. At least 60% of this addition will be peaking capacity fuelled by gas and renewables. The remainder is base-load Queensland capacity fuelled by coal.

Intended New Generation Capacity

Year of estimate	Proposed	Planned	Under Consturction	Actual Increase In Capacity
2000	3,620	3,041	2,638	321
2001	6,086	455	1,708	1,083
2002	3,646	3,111	110	2,481
2003	5,368	2,210	127	-177
2004	11,382	3,062	1,450	105
2005	12,187	2,239	1,575	170
2006	13,620	4,479	1,937	28

Table 1
Intended and Actual New NEM Generation Capacity, 2000 to 2006 (MW) [6]

Source: ESAA (various years)

Wholesale Prices as an Investment Signal?

The level of wholesale prices - particularly, its volatility or spikes - is claimed to signal the need for investment in additional generation capacity (COAG Energy Market Review, 2002; NEMMCO, 2005; NSW Government, 2004; Quiggin, 2003). However, the IEA (2003) claims that investment in base-load generation capacity is being driven by long-term fundamentals rather than short-term wholesale market prices although these do provide sufficient incentive for peaking capacity investment.[7]

Average annual NEM prices (Table 2), with the exception of NSW, have generally shown a downward trend in each region until 2006-07. Similar trends are evident in average monthly NEM prices although a different pattern of volatility is apparent.

Figure 1 shows the average monthly NEM prices for NSW, Queensland and Victoria. There is clearly much more volatility than that shown by the annual averages suggesting further volatility underlying these figures given the 'smoothing' which occurs with monthly averages.[10]

Year ending June	NSW	Queensland	$ per MWh South Australia	Snowy Mountains	Victoria
1999 [9]	33.13	51.65	156.02	32.34	36.33
2000	28.27	44.11	59.27	27.96	26.35
2001	37.69	41.33	56.39	37.06	44.57
2002	34.76	35.34	31.61	31.59	30.97
2003	32.91	37.79	30.11	29.83	27.56
2004	32.37	28.18	34.86	30.80	25.38
2005	39.33	28.96	36.07	34.05	27.62
2006	37.24	28.12	37.76	31.09	32.47
2007	58.72	52.14	51.61	55.19	54.80

Table 2
Average Annual NEM Prices, 1998-99 to 2006-07 [8]

Source: NEMMCO (2007b).

Price volatility within the NEM has been widely acknowledged (ABARE, 2002a; Australian Government, 2004; NSW Treasury, 2001; Productivity Commission, 2005b). The most critical aspect of this volatility is not so much its occurrence but the extent of the price spike and its duration. The Australian Government's white paper, Securing Australia's Energy Future, stated that NEM price spikes in 2002, while "lasting for only 3.2% of the annual duration of the market accounted for 36% of total spot market costs" (2004: 70).

Price spikes have regularly occurred at levels well below maximum demand. From the commencement of the NEM in December 1998 until 31 December 2007, there were nearly 159,000 half-hour trading intervals. During this period, there were around 7,300 trading intervals (4.6%) when the wholesale price was greater than A$200 per MWh, but barely a quarter of these occasions have been at demand levels of 90% or more of maximum annual demand and on only one occasion when the maximum wholesale price paid in a given year was at the maximum annual demand level (NEMMCO, 2008). Demand has certainly not been the driver of NEM price volatility.

The number of generators in the NEM has increased considerably although a small number of companies dominate capacity in each region. Three private owners currently hold ownership interests in more than 55% of Victorian capacity and two of these owners dominate South Australian generation capacity. Government ownership accounts for at least two-thirds of total NEM generation capacity.[11]

It has been claimed that the generation sub-sector is able to push the NEM's prices to a level inconsistent with a competitive market by withholding capacity, either physical (for example, offline for maintenance) or economic, whereby a block of capacity is bid at a higher price band (ABARE, 2002; Booth, 2003). The cause of significant price spikes cannot be attributed to shortages of supply due to transmission congestion or capacity offline for scheduled maintenance (Booth, 2004; COAG Energy Market Review, 2002). The NEM's regulatory regime does however permit re-bidding. The significant extent to which re-bidding moves the volume of generation capacity to a higher price band (at least 50%), and the high proportion of re-bids made within one and a half hours of dispatch (40%), signals the considerable market power held by a few generation companies (Chester, 2006).

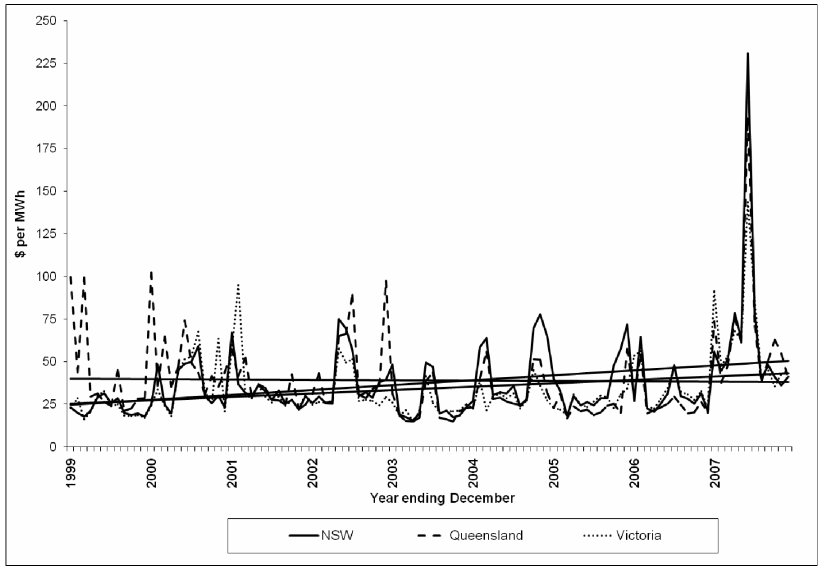

Figure 1
Average Monthly Prices for the NEM Regions of NSW, Queensland and Victoria, 1999 to 2007

Source: NEMMCO (2007b)

Furthermore, the majority of re-bids do not reflect the marginal cost of bringing extra capacity into production – assumed by the market's design – but a higher price to yield a more advantageous financial outcome for the generation company concerned. The long-run marginal cost (LRMCs) for new generation entrants has been estimated at A$38.37–$53.72 per MWh for gas plants and A$31.06-$35.33 per MWh for coal plants (ACIL Tasman, 2005). Annual and monthly NEM prices have predominantly averaged around the lower end of the range for gas plants. Yet, over the period 1999 to 2005, generators were able to sustain revenue – in each year except 2004 - above these estimated LRMCs even after assuming an additional average cost of A$5MWh for hedging (Bardak Ventures, 2005).[12] Such a 'revenue achievement' occurred with wholesale price spikes at levels well below maximum demand. These generators were able to make substantial financial gains by exercising their market power, without breaching the bidding rules of the NEM's regulatory regime. These same generation companies have also provided substantial dividend and tax equivalent payments to their government owners each year (Chester, 2007).

Bidding practices by the NSW government-owned generator Macquarie Generation also contributed to the significant June 2007 price spikes (Figure 1). The Australian Energy Regulator (AER) found that these spikes were caused by an unprecedented congruence of record demand levels during a period of capacity shortage. Prolonged drought conditions restricted water for both cooling (Queensland) and generation (Tasmania and the Snowy region) while flooding and scheduled offline maintenance reduced NSW capacity, and transmission constraints also contributed. Macquarie Generation took advantage of these circumstances and repriced capacity into higher price bands all of which coincided with severe price spikes but did not breach the NEM's regulatory regime (AER, 2007b).

Overall, investment in generation capacity and its relationship to wholesale prices can be summarised as follows:

- The increase in NEM generating capacity to date has been concentrated in two States and dominated by peaking capacity. Only marginal additions to base-load capacity have occurred through augmentation of existing plant;
- Those States to benefit from a peaking capacity increase - South Australia and Queensland - did experience comparatively higher levels of wholesale prices in the early years of the NEM. This correlation, however, has not been sustained. The long-term upward trend in NSW prices has not stimulated private investment even in peaking capacity;
- The trend in wholesale prices is not stimulating investment in base-load capacity notwithstanding the volatility that has occurred;
- Demand has not driven wholesale price volatility; and
- NEM generation capacity is dominated by a handful of companies, the majority of which are government-owned. These companies have exercised their market power, within the NEM's bidding rules, causing wholesale prices to spike and deliver significant financial gains.

The Storm Clouds of Climate Change

Divergent Federal and State government greenhouse gas abatement schemes have been criticised as unsustainable policy and a serious impediment to generation investment (ESAA, 2004; Port Jackson Partners Limited, 2005; Productivity Commission, 2005a).[13]

Climate change and greenhouse gas emissions have become major community concerns with an intensified political debate throughout 2007. The IEA has cited Australia as facing a unique challenge because emission intensity is very high at 1.5% of global greenhouse gas and 43% above the IEA average (IEA, 2005). Electricity generation produces around 38% of Australia's greenhouse gas emissions, coal being primarily responsible. Coal will, however, remain electricity generation's dominant fuel source for many decades given past investment in coal-fired capacity, its suitability for base-load generation, and its low cost relative to other fuels.

The previous Federal Government announced its intention to establish an emissions trading system but no targets were defined. The newly elected Federal government took immediate steps in December 2007 to ratify the Kyoto protocol and has a number of climate change policy commitments including the development of renewable energy, clean coal technology and a national emissions trading scheme. However, the Prime Minister has categorically ruled out the setting of targets to cut greenhouse gas emissions prior to the late 2008 completion of the Garnaut Climate Change Review.[14]

Consequently, critical considerations for new investment in electricity generation are the potential for adverse environmental impacts and the additional costs that may be incurred to meet government emission trading or other forms of abatement schemes.[15] Policy uncertainty, as well as the time needed to develop new commercially viable technologies, makes generation investment planning tenuous at best and adds some support to the IEA claims of base-load capacity investment being driven by long-term fundamentals rather than wholesale price movements.

The Current State of Transmission Interconnections

Regulated interconnectors - ones which have passed the regulatory test, are deemed to add value to the NEM and receive annual revenue determined by regulation regardless of usage - operate between all adjacent regions of the NEM. One interconnector, Basslink, is unregulated and generates revenue from spot price differentials between NEM regions.[16]

The transmission interconnections between NEM regions are shown in Table 2. Only two major interconnections have been built since 1991 - the Queensland-NSW Interconnector (QNI) in 2001 and Basslink, between Tasmania and Victoria, in 2006. Directlink and Murraylink only provided minor additions to capacity. The QNI and the two long-standing Snowy interconnectors provide the greatest transfer capacity within the NEM.

A key NEM objective is to export electricity to a region when demand cannot be met by local generators or when the price of electricity in an adjoining region is lower than local supply. For such trade to occur, high-voltage transmission lines with adequate import–export capacity need to be in place. For NSW and Victoria, import capacity is a little more than a third of their respective generation capacity whereas South Australia and Tasmania have an import capacity of around 19%, and Queensland has 4%.

Interconnector	Region	Maximum transfer capacity (MW)
QNI	Queensland to New South Wales	1080
	New South Wales to Queensland	300
Directlink	Queensland to New South Wales	180
	New South Wales to Queensland	80
SNO-NSW	Snowy Mountains to New South Wales	3000
SNO-VIC	Snowy Mountains to Victoria	1900
VIC-SA	Victoria to South Australia	460
	South Australia to Victoria	330
Murraylink	Victoria to South Australia	220
	South Australia to Victoria	150
Basslink	Tasmania to Victoria	600
	Victoria to Tasmania	480

Table 2
Transmission Interconnector Capacity

Source: AER (2007b)

NEMMCO's scheduling of generators is thus heavily dependent on the physical transfer capacity of available interconnectors. When the technical limit of capacity is reached, local generators must be dispatched to meet outstanding local demand. This means that higher spot prices occur than would be the case without capacity constraints.[17] Transmission constraints contributed to the severe spike in June 2007 NEM prices.

NEMMCO has reported for some years that augmentation is required between Victoria to the Snowy Mountains, Snowy Mountains to Victoria, and Queensland and NSW (both directions) (NEMMCO, 2007a).

As a result of existing interconnector capacities, the NEM operates essentially as six regional markets, with generators and retailers largely trading intra-regionally. Reasons posited for little augmentation include: the absence of national network planning; a lengthy and uncertain approval process for new investments (for example, a proposal to connect SA and Victoria first arose in 1998, took three years for approval but is still to commence due to litigation); flaws in the current regulatory benefits test used to assess augmentation proposals; complex NEM rules and procedures; and agreements to allow unregulated transmission interconnectors which have a strong interest in maintaining NEM regional price differentials (Booth, 2003; COAG Energy Market Review, 2002; Port Jackson Partners Limited, 2005).

The AER has been given responsibility for national transmission planning as well as regulation of transmission pricing and augmentation proposals. The regulatory benefits test has been reviewed and adjusted. There is no evidence, however, of any support for an approach which combines market incentives for small transmission augmentation and incentive regulation for large augmentation projects, an approach regarded by others as possibly the most realistic way to effectively stimulate the expansion of electricity transmission (Hogan, 2003; Rosellón, 2003). In the meantime, proposals for new investment are not materialising.

What are the Prospects for Investment in Sufficient Capacity to Meet Projected Electricity Demand?

The Australian Energy Regulator recently claimed that the "NEM has generated sufficient investment capacity to keep pace with rising demand ... and to provide a 'safety margin' of capacity to maintain the reliability of the power system" (AER, 2007a: 73). The foregoing discussion has signalled a number of reasons which may well prevent this situation from continuing.

Australian electricity demand is growing rapidly, especially peak demand when extreme temperatures occur. Generation capacity has increased although predominantly in Queensland peaking plants. Timely investment in new base-load generation capacity to meet forecast demand and reliability standards is not being stimulated by long-term NEM prices but the sector now relies on price signals to determine new investment. The movement in wholesale prices is not signalling, as widely believed, generation capacity constraints although these are being projected by the market operator. The volatility in wholesale electricity prices is being driven not by demand but a handful of generators exercising market power, and transmission constraints.

Coal is currently the most cost-effective fuel for base-load capacity but one of the highest contributors to greenhouse gas. The dearth of investment in new base-load capacity is being compounded by the prospect of significant capital costs to meet prospective policies requiring reductions in greenhouse gas emissions.

The Australian Energy Regulator (2007) posited that mixed ownership within the sector has led to an 'uneasiness' about investment which privatisation of electricity assets still in public ownership may overcome. A more recent report to the NSW Government contended that public ownership inhibited private sector generation investment which will occur "when wholesale prices and market-related conditions point to a decision based upon commercial criteria" (Owen, 2007: vii). If this is the case, no new private sector investment will occur until all generation assets are privatised. Other than marginal augmentation to base-load capacity has occurred since the privatisation of Victorian and South Australian generation assets. The impending sale of NSW generation will mean that 60% of NEM capacity will be privately owned. Is this a sufficient level of private ownership to allay the alleged uneasiness before private investment commences? Or will the remaining 40% - held in government ownership across Queensland, the Snowy Mountains region and Tasmania – need to be also privatised for there to be a sufficient investment stimulus? The NSW sale will take at least 18 months to achieve assuming current community opposition dissipates sufficiently. Further potential privatisations would extend the timeframe considerably. In the meantime, demand grows and capacity tightens.

But what of the level of wholesale prices, potential climate change policies and transmission capacity? Will new private owners of progressively privatised generation assets exercise market power as owners before them have done and manipulate wholesale price outcomes to earn sufficient returns to repay debt used to purchase generation assets, meet LRMCs and provide healthy financial payouts to their shareholders? Without changes to the NEM bidding rules, it is difficult to see why such opportunities would be overlooked notwithstanding that new entrants will remain dissuaded. As for climate change policies, it will take some years for these to be formulated and fully implemented. In the meantime, demand grows and capacity tightens.

Privatisation of NSW, or any other generation assets, will not be sufficient in itself to stimulate timely capacity investment in order to meet forecast demand. Clearer definition of climate change policies and their application will provide greater certainty about potential costs. But until these costs are known and the extent to which government may assist implementation, private investors will not commit to new capacity. Moreover that commitment will be muted without sufficient augmentation to transmission capacity to ameliorate the current constraints on import-export.

On the basis of current policy settings, the time horizon for investment in sufficient generation and transmission capacity to meet forecast demand over the next 10 years is bleak and the security of Australia's electricity supply is under threat.

Footnotes

[1] The land area of Australia is roughly comparable to the United States although more than 85% of the population is concentrated along the eastern seaboard and in the south-east. The NEM covers the southern and eastern States and Territories (Queensland, NSW, ACT, Victoria, Tasmania and South Australia). The geographic remoteness of the population centres of Western Australia and the Northern Territory make the cost of transmission interconnection to a national grid prohibitive.

[2] Privatisation of former government electricity companies has occurred but not to the extent often claimed. The NSW Government's November 2007 announcement of its intention to sell its generation and retail assets will result in around 60% of NEM generation capacity being privately owned.

[3] Spain's centralised market is only part mandatory.

[4] In NSW, summer peak demand increased by 3.8% per annum from 1999 to 2004 while average demand grew annually by 2.8%. The forecast growth in peak power demand in Victoria is 3% per annum until 2020 compared to total growth in demand of 2% each year.

[5] These projections are based on the generating and transmission capacity to maintain the agreed standard of supply reliability within each NEM region. The system is deemed reliable if, over the long-term, at least 99.998% of consumer energy demand can be met.

[6] Proposed refers to proposals that have not been fully evaluated or received all necessary approvals to become a more definite prospect of proceeding. Planned is equivalent to a definite commitment although still subject to final decisions before construction is commenced. Not all of the proposals in this latter group will be found to be sufficiently viable to proceed to full planning.

[7] The more capital-intensive base-load generation (for example, coal) is costly and hence, it is claimed that investment will be stimulated by a long-term trend in higher prices. Less capital-intensive plants (for example, gas) are easier to start up, although more expensive to operate, and thus highly suitable to supply short peak periods of demand. Investment in these peaking plants will also require a sustained trend in higher prices but, being of a lower capital cost, the payback period is considerably shorter.

[8] Tasmania is not included because data is only available from mid 2005.

[9] Seven months only from December 1998 to June 1999.

[10] Average monthly figures for each NEM region are derived from over 1,400 prices given the 48 half-hour trading intervals per day and, for the majority of the year, at least 30 trading days per month. A more complex picture of volatility is shown by average daily and half-hourly spot prices (see Chester, 2006).

[11] In 1995 there were nine government-owned generation companies, two privately owned and four integrated government companies. By the end of 2006, this group of companies had grown to 24 (nine government, thirteen private and one integrated). In addition, a number of private generators had commenced operating.

[12] During 2002-05, only NSW and Queensland (government-owned) generators exceeded the new entry LRMCs. Victorian generators were broadly equivalent and those in South Australia below.

[13] For example, the Federal government's Mandatory Renewable Energy Target scheme has been criticised for being biased towards wind power which is far more costly than conventional energy but is only available when there is wind. Hence, conventional energy is required as a back-up which adds considerably to capital costs. The NSW Greenhouse Abatement Scheme has been found to lead to minimal cuts in emissions but with considerable costs to electricity consumers.

[14] This review was commissioned in April by the Federal Labor Party, when in opposition, and all State and Territory Governments. A final report is due in September 2008.

[15] In 2005, the Victorian government reached agreement with International Power, majority owner of Hazelwood Power (1600MW), for a reduction in emissions of 34 million tonnes during the next 25 years in return for access to 43 million tonnes of brown coal. Currently the generator emits 17 million tonnes per annum of greenhouse gases and will need to spend A$400 million to meet the agreed target.

[16] Two interconnectors, Murraylink and Directlink, were built as unregulated interconnectors but subsequently met the regulatory test in 2003 and 2006 respectively.

[17] It is claimed that NEM regional price differentials, due to transmission capacity constraints, have added from A$1.6 to 2.6 billion to the cost of wholesale electricity each year since 1999 (Port Jackson Partners Limited, 2005). The cost of transmission network congestion has been estimated at: A$36 million in 2003-04, A$45 million in 2004-05, A$66 million in 2005-06 and A$107 million in 2006-07 (AER, 2007c).

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IAEE is pleased to announce its 2008 Best Student Paper Contest in conjunction with the IAEE Istanbul International Conference. A top prize of $1000 will be given for the best paper in energy economics. Two runners up prizes of $500 each will also be given. All three winners will receive a waiver of registration fees to the Istanbul International Conference on June 18-20, 2008. To be considered for the IAEE Best Student Paper Award please follow the guidelines below.

- The student must be a member in good standing of IAEE. Membership information may be found at https://www.iaee.org/en/membership/application.aspx
- Completed papers must be submitted to IAEE headquarters in PDF format by May 1, 2008. The submitted paper should be double-spaced and not exceed 30 pages in length. Any paper that exceeds this page limitation will be subject to disqualification.
- The paper MUST be an original work completed by the student as part of an academic program and may not be co-authored by a faculty member. The student must be the sole author.
- Submittals must include a letter stating that he/she is a full-time student or have completed a degree within the past 12 months. 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 of your main faculty advisor or your department chair. Please also, include a copy of your student identification card.
- Submittals must include a letter from your faculty member, preferably your faculty advisor, confirming the work is your own and recommending the paper for consideration.

Complete applications should be submitted electronically to IAEE Headquarters office no later than May 1, 2008 for consideration. All materials should be sent to iaee@iaee.org

NOTE: Award recipients must be present in Istanbul to receive their cash prizes. Please note that all travel (ground/air, etc.) and hotel accommodations, meal costs (in addition to conference-provided meals), etc., will be the responsibility of the award recipient.

For further questions regarding IAEE's Best Student Paper Contest, please do not hesitate to contact David Williams, IAEE Executive Director at 216-464-2785 or via e-mail at: iaee@iaee.org

31st IAEE International Conference

Istanbul, June 18-20, 2008

Sixteen members of the Istanbul Program Committee gathered in Istanbul February 9-10 for the fourth International Program Committee (IPC) meeting. Over 430 abstracts were received for conference presentation consideration. Topics mainly addressed at this meeting were accepting/allocating abstracts into concurrent sessions, plenary session speaker confirmations, budget and sponsorship. If you are planning to attend the Istanbul conference we STRONGLY recommend that you make your hotel reservations soon as we anticipate the hotel sleeping room block to sell out quickly.

Members of the 4th IPC meeting at work accepting and allocating abstracts into concurrent sessions.

Pictured above (left to right) are Ilhan Or, International Program Committee Chairman, Georg Erdmann, IAEE President-Elect, and Gurkan Kumbaroglu, TRAEE President and General Conference Chairman.

Forecasting Chinese Energy Demand: Is the World in Denial?

By Malcolm Shealy and James Dorian*

Introduction and Background

Only a few years ago Chinese government leaders were optimistic that their country could quadruple its GDP between 2000 and 2020 while only doubling energy use. For any other developing country this would be considered an unrealistic goal, as energy consumption during development tends to grow as fast or even faster than GDP. Yet, China had quadrupled GDP while only doubling energy use from 1980 through 2000, so government officials reasoned they could do it again.

However, China is already off track in meeting its 2000-2020 energy consumption goals, and the country is now at a point where it will be nearly impossible to prevent energy use from more than doubling. As shown in Figure 1 energy use has grown faster on average than GDP since 2000. Notwithstanding, China's government, as well as major energy statistics agencies including the International Energy Agency (IEA) and United States Department of Energy (DOE), have been so captivated by the original, optimistic story-line that even their latest forecasts have not caught up to the reality of what is happening in China.

In this article we first examine the period from 1980 through 2000, and explain why it was unusual for the Chinese energy industry. Second, we look at the changes in China since 2000, including the critical electric power generating sector. Using a simple thought experiment, we then illustrate that even with very conservative assumptions about Chinese GDP growth and income elasticity of electric demand out to 2025, the country will experience much higher coal demand and emit much greater volumes of carbon emissions than forecast by IEA, DOE, as well as other forecasters. This leads to some final thoughts on the implications of future Chinese energy demand on global energy markets.

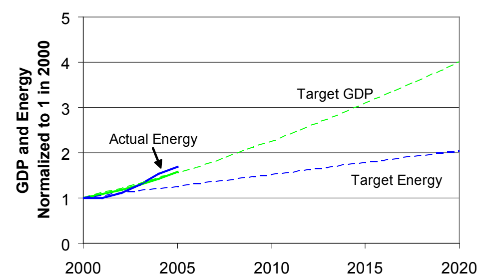

Figure 1
Actual Energy Use in China is Well Above Target Since 2000.

Why the 1980-2000 Period in China Was Unusual

During the 20 year period from 1980 through 2000, China quadrupled GDP while only doubling energy use. This is quite unusual. Developing country energy use typically grows faster than GDP as heavy industry develops and as consumers transition from non-market fuels such as firewood to market-based fuels such as kerosene and electricity.

Even more unusual for China was the weak growth in electric demand. Electricity is the most versatile, high-quality source of energy. In developing countries electricity consumption is expected to grow faster than GDP, which implies an income elasticity of over 1.0. Yet, from 1980 through 2000 in China, electricity consumption grew only about 80 percent as fast as GDP, yielding an income elasticity of around 0.8. In addition, reported growth in coal consumption slowed significantly in China during the late 1990s, fueling optimism that China was somehow different—that its economy could grow faster than energy use on a continuing basis and even transition away from coal.

Various explanations have been offered for why Chinese energy demand grew so much slower than for other developing countries. One prominent explanation is that the Chinese were transitioning from inefficient state enterprises to more modern and efficient means of production. The consequent efficiency improvements meant that the economy could grow faster than energy use. Another explanation is that faulty Chinese GDP or energy statistics led to skewed income elasticities. Regardless of the actual reasons, the picture has recently changed.

Relationship Between Energy and Economic Growth Changed Abruptly After 2000

The Chinese economy is vastly different today than it was two decades ago. Energy linkages throughout the economy are greater than before, more costly and complex, more reliant on long-distance transport within China, and more dependent on foreign supply chains of oil, gas, and increasingly, coal. Since the 1980s, hundreds of thousands of kilometers of new pipelines, railroads, and highways have been built, which are necessary to move increasingly larger volumes of oil, gas, and coal throughout the country. Oil use for vehicle transportation in China has grown several-fold since the 1980s. Energy prices have been decontrolled and allowed to rise to near market or market levels.

* Malcolm Shealy is a Senior Energy Analyst for PCI in Arlington, Virginia. Email: malshealy@embarqmail.com James P. Dorian is an International Energy Economist based in Washington, D.C. Email: jamesdorian@yahoo.com This paper represents an updated version of "Growing Chinese Energy Demand: Is the World In Denial?," published by the Center for Strategic and International Studies (CSIS), Washington, D.C., October 2007. All opinions, analyses and statements are solely those of the authors and do not reflect the official position of any U.S. or international organization or government agency.

Beginning in 2000, the observed relationship between energy and GDP began to change. First, the growth rate in electricity consumption rose above the growth rate in GDP for the first time in years, and continued to grow faster than GDP, yielding an income elasticity averaging 1.3 over the period 2000-2006. This sudden change in the nature of electricity demand occurred for two primary reasons: (1) the inefficient state enterprises have now become relatively more efficient and, as such, achieving additional energy savings from industry today is more challenging and costly; and (2) the Chinese economy has grown enormously, resulting in a smaller share of the pie for state enterprises. Today, Chinese electricity demand is behaving like that of a normal developing country and shows no sign of reverting to the earlier pattern. Indeed, Chinese goals for rapid urbanization of upwards of 400 million people by 2030 will likely push electricity demand up even faster.

A second major change is the rapid increase in coal use starting in 2002. Part of this increase represents catching-up after the underreporting of the late 1990s when the Chinese government had attempted to shut down thousands of small inefficient coal mines in order to meet World Trade Organization ascension requirements. Another reason is that coal use is increasingly driven by electric demand. For example, in 1990, about 25 percent of coal production went to electric utilities; by 2005, that figure had grown to 55 percent. Clearly, robust growth in electricity consumption since 2000 has contributed to robust growth in coal demand—as almost 80 percent of Chinese power generation is coal-fired. The increase in coal use, along with a substantial increase in oil demand, has caused Chinese energy demand to rise at a rate of about 11.2 percent per year from 2000-2005, while GDP growth has averaged 9.6 percent per year.

What Does China's Energy Future Look Like Through 2025?

We next examine what the future may hold for China's energy consumption using a simple thought experiment, then compare the results to the most recent IEA and DOE forecasts. Given that seven years have passed since 2000, we have chosen to forecast over the 20-year time period from 2005 through 2025. Complete historical data is available through 2005, while some data is available through 2006. Since electricity increasingly drives Chinese energy demand, we begin with a discussion of electricity.

Electricity

To be conservative, we assume that Chinese electricity consumption grows only 1.1 times as fast as GDP through 2025, down from its current ratio of 1.3. Figure 2 shows how Chinese electric demand would grow for two different average GDP growth rates—6.5 percent and 7.2 percent. The 6.5 percent GDP growth rate is close to the IEA and DOE GDP growth assumptions. The 7.2 percent growth rate was chosen because it gives a quadrupling of GDP over 20 years, so corresponds to the targeted Chinese growth rate. Figure 2 also shows recent IEA and DOE forecasts of Chinese electric demand.

Why are the IEA and DOE forecasts significantly lower than the lowest-growth thought experiment? IEA and DOE assume low GDP growth rates, but also assume income elasticities that are much lower than those we have witnessed recently in China. For example, the IEA November 2007 reference case forecasts that from 2005 through 2030 electricity consumption will grow significantly slower than GDP—4.9 percent average annual growth in electricity versus 6.0 percent growth in GDP—which implies an income elasticity of only 0.82. The Chinese forecasts also imply an unreasonably low income elasticity of electric demand.

As the IEA and DOE forecasters have been confronted by rapidly rising near-term electric consumption in recent years, they have repeatedly shifted their forecasts upward (see Figure 3). These forecasting problems will continue until IEA and DOE update the relationship between growth in electricity consumption and growth in GDP.

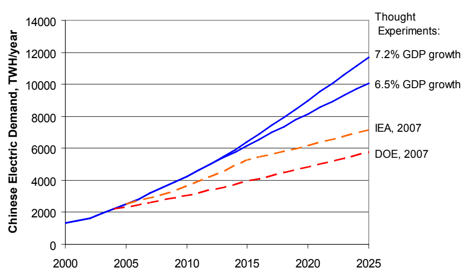

Figure 2
The Thought Experiments Yield Much Higher Forecasts of Chinese Electric Demand in 2025 than IEA or DOE.

Coal

Electricity demand increasingly drives coal demand in China. The Chinese electric sector accounted for 55 percent of Chinese coal demand in 2005, and the share has been steadily rising. As IEA, DOE, and the Chinese government underforecast Chinese electric demand, they subsequently underestimate Chinese coal demand.

Figure 4 continues our thought experiment by demonstrating how Chinese coal consumption would grow for three different average GDP growth rates to 2025--6.5 percent, 7.2 percent and 10 percent per annum. This computation is conservative in three important respects. First, it assumes more rapid growth in non-coal electric generation than posited by either IEA or DOE (e.g., a tripling of hydro generation by 2025 and a 10-fold increase in nuclear generation). Second, it assumes that the efficiency of converting coal to electricity is higher than the IEA historical data implies, and that the efficiency is rising over time. Third, it assumes that non-electric coal consumption (e.g. for iron and steel) grows only one-fifth as fast as GDP--meaning that a 10 percent growth in GDP causes only a 2 percent growth in non-electric coal consumption.

Despite conservative assumptions, with a 7.2 percent GDP growth rate in China to 2025, the country would use over 6 billion tons of coal in 2025, almost three times the current amount of coal produced and used. Cumulatively this amounts to 86 billion tons of coal from 2005 through 2025, out of a roughly 115 billion ton reserve base—implying much reduced domestic coal availability by the end of the period. The main culprit for the rapid rise in coal demand is the rapid growth in electricity consumption. To our knowledge, there are no forecasts today suggesting a tripling of coal use in China within two decades, or what the ramifications of such growth could mean to the world's efforts to combat global warming.

Such rapid growth in coal use through 2025 would present major challenges to the Chinese economy, environment, and transportation system, and it would raise some doubt as to whether China could even meet a 7.2 percent average annual growth rate to 2025. Indeed, China's railroad cars and tracks are already over-burdened, and a competition for limited rail car use has developed among coal, iron ore, steel, grains, and many other commodities, including oil (see Figure 5). The increase in coal transport by rail is outpacing rail track expansion in China, displacing other freight, and accelerating a shift to less efficient transport by road. Looking ahead, it is difficult to envision how another 4 billion tons of coal per year could be produced, transported and used in China, even with plans for dramatic railroad expansion now called for in China's 11th Five-year Plan. Since China has become a net coal importer this year, increasing volumes of coal would have to be imported to meet a tripling of use—and it is very questionable where such potentially huge volumes of coal would come from.

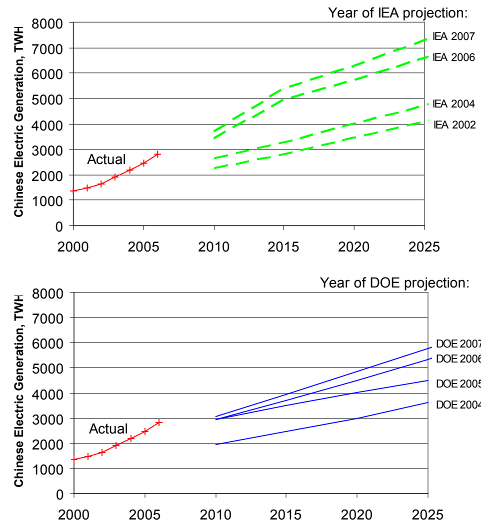

Figure 3
Like Most Chinese Electricity Demand Forecasts, IEA and DOE are Consistently Revised Upwards

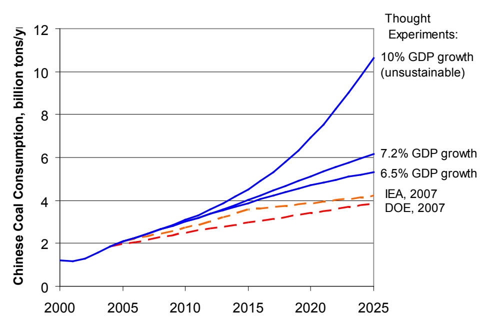

Figure 4
The Thought Experiments Yield Much Higher Forecasts of Chinese Coal Demand in 2025 than IEA or DOE.

Oil

Oil consumption in China has risen only about 70 percent as fast as GDP, yielding an income elasticity of 0.7. However, that picture may change soon. First, the Chinese are purchasing vehicles at a very rapid rate, and the notion from a few years back that the Chinese are somehow different and will be content to ride bicycles has been disproved (see Figure 6). Second, bottlenecks in rail can divert goods to long-haul trucking, which uses far more oil per ton-mile. Finally, the Chinese industrial base is a major consumer of petrochemicals and is growing rapidly.

Carbon Emissions

Coal supplies about 70 percent of Chinese energy needs, and this percentage is likely to remain high for decades, as coal is less expensive than many of the alternative fuels available to China. Coal, therefore, will remain the dominant contributor to Chinese carbon emissions looking ahead. Figure 7 shows the impact of growing coal consumption in China on carbon emissions, as well as growing oil and natural gas use. Once again, our thought experiments yield much higher numbers than either the IEA or DOE reference cases, even with conservative assumptions. Importantly, the Chinese could possibly double U.S. carbon emissions by 2025—China overtook the US in 2006 according to Dutch scientists. Such expected growth in carbon emissions in China implies that worldwide efforts toward reducing global warming and greenhouse gas emissions will likely be overwhelmed by China if the country's current path of energy and economic development continues.

Only Way Out: Slower Economic Growth

Various alternatives have been proposed for reducing Chinese dependence on fossil fuels and slowing the growth of coal use and Chinese carbon emissions. Such alternatives have included boosting nuclear and wind power, increasing use of biofuels, rapidly developing a natural gas and LNG domestic industry, and increasing energy efficiency in power generation and end uses through price and policy reform. Each option has limitations and challenges. However, to keep with a conservative scenario, our thought experiment assumes relatively rapid penetration of all of these alternatives—often more rapid than assumed by IEA and DOE. Nonetheless, even under optimistic assumptions regarding alternative energy forms in China, the share of electricity generated by coal through 2025 increases in the 7.2 percent GDP growth case, and remains about the same in the 6.5 percent GDP growth case. The reason is that the income elasticity

Figure 5
China's Coal Deposits and Major Rail Infrastructure.

of 1.1 drives electricity consumption upward at a rapid rate, one that cannot be matched by hydro, nuclear, and renewables as a group.

China has ample opportunity to increase the energy efficiency of its economy. But without dramatic and even unprecedented price and policy reform there will likely be limitations on how much efficiency gains can slow growth in overall energy consumption. China's reliance on coal power plants, for example, will remain the norm without a dismantling of the huge power monopoly—which is improbable. While efficiency gains are possible throughout Chinese industry, including within the cement, iron ore and steel, and chemical sectors, gains to date have not managed to reverse rising energy demand. More importantly, China's continuing drive to achieve robust economic growth and maintain jobs—particularly at the local and provincial levels—will keep the primary focus of industry on output and not on reduction in energy use.

With alternative fuels and energy efficiency gains likely offering only marginal help in reducing Chinese coal reliance to 2025, slower economic growth is probably the only viable solution to the current skyrocketing growth in Chinese energy demand. If the Chinese government does not reign in economic growth in a controlled manner, then various bottlenecks in the energy supply system or environmental problems will probably force them to slow their growth in a less-controlled manner.

Figure 6
Chinese Bicycle Congestion has Given Way to Auto Congestion.

Conclusions and Implications

As shown by our thought experiment, the IEA and DOE reference case scenarios do not represent a continuation of current trends, but instead assume an unexplained, radical reduction in Chinese energy intensity. This is evidenced by their repeated upward revisions of projections for electricity, coal, and energy in general, as well as by an unreasonably low income elasticity of electricity consumption. The actual trajectory for Chinese energy consumption is proving to be much higher than their forecasts, and this trend will continue until IEA and DOE come to grips with the high income elasticity of electric demand.

Our trajectory for Chinese coal consumption to 2025 has stark implications both for sustained Chinese economic growth as well as for the world's environment. The authors believe the world has not yet come to grips with the possibility of coal use in China increasing three-fold over today's levels. As such, we believe further studies are warranted to address this issue and answer fundamental questions suggested by our analysis, including: (1) will infrastructure bottlenecks in the all-important Chinese coal sector lead to a slowdown in economic growth sometime next decade; and (2) if energy forecasters consistently underestimate long-term Chinese energy demand, how accurate are their forecasts of global energy consumption. The risk of denial is that China and the world fail to recognize the magnitude of the task ahead in meeting energy needs, and thus fail to act soon enough to prevent significant disruptions.

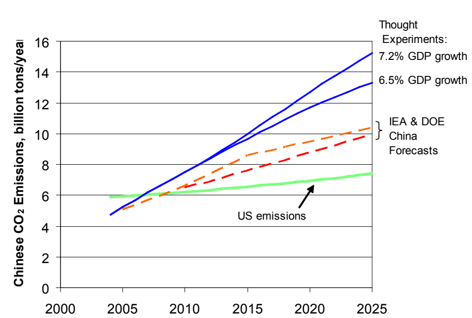

Figure 7
IEA and DOE Forecasts Significantly Understate the Potential Growth in Chinese Carbon Emissions.

Multi-Greenhouse Gas Mitigation and Climate Policy

Guest Editors: Francisco C. de la Chesnay and John P. Weyant

This Special Issue of *The Energy Journal*, entitled Multigas Mitigation and Climate Policy, presents the results of the most recently completed study organized by Stanford University's Energy Modeling Forum (EMF), commonly referred to as EMF-21. Edited by John Weyant, Stanford Univ., and Francisco de la Chesnaye, U.S. EPA, the 520-page volume is the largest and most comprehensive international, coordinated study on greenhouse gas (GHG) scenarios to date.

This Special Issue provides a complete report on a comparative set of analyses of the economic and energy sector impacts of multigas mitigation of anthropogenic GHGs, including carbon dioxide (CO_2) and the more potent non-CO_2 GHGs including methane (CH_4), nitrous oxide (N_2O) and a set of fluorinated gases (PFCs, HFCs and SF_6). In 2000, energy-related CO_2 emissions accounted for about three-quarters of global emissions, with the combination of non-CO_2 gases making up the rest on a CO_2-equivalent basis.

The objectives of this study were to: (1) conduct a multigas policy assessment to improve the understanding of the affects of including non-CO_2 GHGs and terrestrial sequestration into short and long-term mitigation policies; and (2) advance the state-of-the-art in integrated assessment and climate economic modeling. Nineteen energy-economic modeling teams from Asia, Europe, and the U.S. along with international experts on non-CO_2 GHGs and forestry participated in the study. Many of the modelers who participated in EMF-21 have now formed a new international consortium (supported by the new EMF-22 study) to develop the next round of global economy, energy, and GHG scenarios.

Results from EMF-21 provide reference projections of all GHGs to 2100 and also estimate the economic effects of meeting a stabilization target of 4.5 Wm-2 (watts per square meter) relative to pre-industrial times, which corresponds to an equilibrium temperature increase of 3.0°C. Although the models project that CO_2 emissions grow throughout the century, the range of reference case projections is quite large, with projections from some models showing slightly more than a doubling and others showing an approximate five-fold increase over the century. The reference emissions for CH_4, the second most important GHG, show about a doubling of emissions over the century. For the climate stabilization case, all models show that climate mitigation under a multigas policy leads to an appreciable reduction in both marginal costs and effects on global GDP.

The two principal insights from the study are: (1) the range of economic sectors from which non-CO_2 GHGs originate is far larger and more diverse than for CO_2; and (2) the mitigation costs for these sectors and their associated gases can be lower than for energy-related CO_2 alone. Taken together, these two factors result in a more diverse portfolio of potential mitigation options, and thus the potential for reduced costs, for a given climate policy objective.

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Abstract Submission Deadline: 14 July 2008

Authors will be notified by **28 July 2008**, of their paper status. Authors whose abstracts are accepted will have to register and submit their full-length papers before **1 September 2008**. Accepted abstracts will appear in the proceedings, which will be distributed at the conference. Other related documents are available on the conference website: www.cbs.curtin.edu.au/aaee2008

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The official conference hotel is the Medina Grand Perth, an apartment hotel which is adjacent to the conference venue. However, there is a widely-priced range of hotels situated within a short distance of the PCEC.

How to get to Perth

Qantas, Australia's international carrier, operates a comprehensive network of international flights in association with its One World alliance partners. From the USA, flights are routed through Australia's east coast gateway cities, giving participants the opportunity to visit Sydney, Melbourne, or Brisbane. From Europe, one stop flights to Perth involve a change of plane in an Asian hub. Emirates offer direct flights from the Middle East, whilst a host of national carriers offer direct flights from Asian capital cities.

I look forward to seeing you in Perth

Professor Tony Owen
Conference Chair
Curtin Business School
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Publications

Renewable Energy Engineering and Technology: A Knowledge Compendium. V.V.N. Kishore (2008). 925 pages. Price: US$185.00. Contact: TERI Press, The Energy and Resources Institute, Darbari Seth Block, IHC Complex, Lodhi Road, New Delhi, 110 003, India. Phone: 91-11-2468-2100. Fax: 91-11-2468-2144. Email: teripress@teri.res.in URL: www.teriin.org

International Competition for Resources. Philip Andrews-Speed, Editor (2008). Price: £35.00. Contact: Rona Carstairs, University of Dundee's Centre for Energy, Petroleum and Mineral Law and Policy, Information Services Manager, University of Dundee, Dundee, United Kingdom. Email: r.m.carstairs@dundee.ac.uk URL: www.cepmlp.org

Calendar

5-7 May 2008, Athens Summit - Global Climate and Energy Security at Athens, Greece. Contact: Iris Gavriilidi, Promotional Activities' Coordinator, AC&C International SA, Pierias 1A, Athens, 144 51, Greece. Phone: 30-210-688-9147. Fax: 30-210-684-4777 Email: igavriilidi@acnc.gr URL: www.athens-summit.com

11-16 May 2008, Large scale Gas Projects Course 5 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

11-16 May 2008, Gas Market Regulation Course 5, part 2 at Russia. Contact: Richard Sanders, Study Adviser, Energy Delta Institute, Laan Corpus den Hoorn 300, P.O. Box 11073, Groningen, 9700 CB. Phone: +31 50 524 8332. Fax: +31 50 524 8301 Email: info@energydelta.nl URL: www.energydelta.org

12-16 May 2008, Arbitration & Dispute Resolution for Oil & Gas Master Class Training Course 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. Phone: +44 20 7978 0042. Fax: +44 20 7978 0099 Email: vwalker@thecwcgroup.com URL: http://www.thecwcgroup.com/train_detail_home.asp?TID=27

12-16 May 2008, International Gas Value Chain 5 at Groningen. Contact: Richard Sanders, Study Adviser, Energy Delta Institute, Laan Corpus den Hoorn 300, P.O. Box 11073, Groningen, 9700 CB, Netherlands. Phone: +31 50 524 8332. Fax: +31 50 524 8301 Email: info@energydelta.nl URL: www.energydelta.org

12-16 May 2008, Global LNG - the Complete Supply Chain (Training Course) at Oxford, UK. Contact: Ms. Lesley Rigg, The Oxford Princeton Programme, 1st Floor, 59 St. Aldates, Oxford, OX1 1ST, UK. Phone: +44-1865 250521 Email: info@oxfordprinceton.com URL: http://www.oxfordprinceton.com/search/coursedetails.asp?ID=318&PLP=LNG1

13-14 May 2008, Energy Risk Asia 2008 at Singapore. Contact: Pablo Cot Gonzalez, Incisive Media. Phone: +852 3411 4888 Email: pablocg@incisivemedia.com URL: www.energyriskasia.com

19-23 May 2008, LNG & Gas Contracts & Risk Assessment Training Course at Port of Spain, Trinidad. 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=29

22-24 May 2008, Corporate Climate Response at London. Contact: Annie Ellis, Green Power Conferences. Phone: +442078016333. Fax: +442079001853 Email: info@greenpower-conferences.com URL: http://www.greenpowerconferences.com

2-6 June 2008, 16th European Biomass Conference & Exhibition - From Research to Industry and Markets at Convention and Exhibition Centre of Feria Valencia, Spain. Contact: Anna Andretta, ETA Renewable Energies, Piazza Savonarola 10, Florence, 50132, Italy. Phone: 0039 055 5002174. Fax: 0039 055 573425 Email: biomass.conference@etaflorence.it URL: http://www.conference-biomass.com

8-10 June 2008, 13th Annual Asia Oil & Gas Conference at Kuala Lumpur Convention Centre. Contact: Conference Coordinator, Petronas AOGC, Level 35, Tower 1, Petronas Twin Towers, Kuala Lumpur City Centre, Kuala Lumpur, 50088, Malaysia. Phone: 6-03-52331-4548. Fax: 6-03-2331-1543 Email: aogcsecretariat@petronas.com.my URL: www.aogc-petronas.com

9-13 June 2008, Project Economics & Decision Analysis in Oil & Gas 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=17

15-20 June 2008, Large scale Gas Projects Course 5 part 2 at Russia. 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

16-17 June 2008, Electrifying the Future: Building a Sustainable Energy Market at Barcelona, Spain. Contact: Emily O'Leary, Events Coordinator, Eurelectric, Blvd de L'Imperatrice 66, Brussels, 1000, Belgium. Phone: 32-2-515-10-62. Fax: 32-2-515-10-69 Email: eoleary@eurelectric.org URL: www.eurelectric.org

16-20 June 2008, Advanced LNG Training Course at Hotel Bernini Bristol. 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=26

18-20 June 2008, 31st IAEE International Conference - Bridging Energy Supply and Demand: Logistics, Competition and Environment at Istanbul, Turkey. Contact: Gurkan Kumbaroglu, General Conference Chair, Bogazici University, Istanbul, Turkey. Phone: 90-212-359-7544. Fax: 90-212-265-1800 Email: traee@boun.edu.tr URL: www.iaee08ist.org

23-24 June 2008, CIRED Seminar 2008: SmartGrids for Distribution at Frankfurt, Germany. Contact: Paula Brewer Email: pbrewer@theiet.org URL: www.ciredsmartgrids.org

23-27 June 2008, World Legal Systems & Contracts for Oil & Gas Training Course 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=15

23-24 June 2008, BioFuels 2010 at Houston, TX. Contact: Conference Coordinator, World Trade Group, USA. Phone: 416-214-0173. Fax: 416-214-3403 URL: www.biofuels2010.com

2-4 July 2008, Renewable Energy Philippines 2008 Conference at Metro Manila, Philippines. Contact: David Chow, Director, DP Link International Pte Ltd, 190 Middle Road, #19-05 Fortune Centre, Singapore, 188979, Singapore. Phone: 65-6826 1289. Fax: 65-6826 3373 Email: davidchow@dp-link.com URL: http://www.dp-link.com/exibitions/REP2008/index.html

23-23 July 2008, Gas to Liquids - A New Gas Horizon at London, UK. Contact: Ms. Lesley Rigg, The Oxford Princeton Programme, 1st Floor, 59 St. Aldates, Oxford, OX1 1ST, United Kingdom. Phone: +44-1865 25021 Email: info@oxfordprinceton.com URL: http://www.oxfordprinceton.com/search/coursedetails.asp?ID=344&PLP=GTL%5CAGBR08

17-22 August 2008, Scaling Up: Building Tomorrow's Solutions at Pacific Grove, CA. Contact: Conference Secretariat, ACEEE Summer Study Office, PO Box 7588, Newark, DE, 19714-7588, USA. Phone: 302-292-3966. Fax: 302-292-3965 Email: rlunetta@verizon.net URL: www.aceee.org/conf/08ssindex.htm

August 30, 2008 - September 5, 2008, 7th International NCCR Climate Summer School "Key Challenges in Climate Variability and Change" at Centro Stefano Franscini, Monte VeritÃ , Ticino, Switzerland. Contact: Monika Waelti, University of Bern, NCCR Climate Management Centre, Erlachstrasse 9a, Bern, CH-3012, Switzerland. Phone: +41 31 631 31 45. Fax: +41 31 631 43 38 Email: nccr-climate@giub.unibe.ch URL: http://www.nccr-climate.unibe.ch/summer_school/2008/index_en.html

8-10 September 2008, Smart Energy Strategies at Zurich, Switzerland. Contact: Conference Coordinator, Energy Science Center, ETH Zurich, MLK20, Sonneggstrasse 3, Zurich, CH-8092, Switzerland. Phone: 41-44-632-83-88. Fax: 41-44-632-13-30 Email: info@esc.ethz.ch URL: www.esc.ethz.chsms08

17-19 September 2008, Geo Inida 2008 at Greater Noida, New Delhi. Contact: Ms. Peggy Pryor, Conference Organiser, AAPG, USA. Phone: 1-918-560-2641. Fax: 1-918-560-2684 Email: ppryor@aapg.org URL: www.aapg.org

22-25 September 2008, Global LNG - the Complete Supply Chain (Training Course) at Cape Town, South Africa. Contact: Ms. Lesley Rigg, The Oxford Princeton Programme, 1st Floor, 59 St. Aldates, Oxford, OX1 1ST, UK. Phone: +44-1865 250521 Email: info@oxfordprinceton.com URL: http://www.oxfordprinceton.com/search/coursedetails.asp?ID=318&PLP=LNG1

6-17 October 2008, Master of Petroleum Business Engineering 2008, module 1 at Groningen. Contact: Richard Sanders, Study Adviser, Energy Delta Institute, Laan Corpus den Hoorn 300, P.O. Box 11073, Groningen, 9700 CB, Netherlands. Phone: +31 50 524 8332. Fax: +31 50 524 8301 Email: info@energydelta.nl URL: www.energydelta.org

6-8 October 2008, Hydro 2008 - Progressing World Hydro Development at Ljubljana, Slovenia. Contact: Mrs. Margaret Bourke, Conference Coordinator, Hydro 2008, Aqua Media Intl Ltd, Westmead House, 123 Westmead Rd, Sutton, Surrey, SM1 4JH, United Kingdom. Phone: 44-20-8643-5133. Fax: 44-20-8643-8200 Email: mb@hydropower-dams.com URL: www.hydropower-dams.com

13-17 October 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

20-31 October 2008, Executive Master of Gas Business Management 2008, module 1 at Groningen. Contact: Richard Sanders, Study Adviser, Energy Delta Institute, Laan Corpus den Hoorn 300, P.O. Box 11073, Groningen, 9700 CB, Netherlands. Phone: +31 50 524 8332. Fax: +31 50 524 8301 Email: info@energydelta.nl URL: www.energydelta.org

4-7 November 2008, Global LNG: Import & Regasification Europe at Zagreb, Croatia. Contact: Ms. Lesley Rigg, The Oxford Princeton Programme, 1st Floor, 59 St. Aldates, Oxford, OX1 1ST, United Kingdom. Phone: +44-1865 250521 Email: info@oxford-princeton.com URL: http://www.oxfordprinceton.com/search/coursedetails.asp?ID=347&PLP=LNGIM%5CAABW08

5-7 November 2008, 2nd IAEE Asian Conference at Perth, Western Australia. Contact: Tony Owen, Professor, Curtin Business School, Curtin University of Technology, GPO Box U1987, Perth, WA, 6845, Australia Email: tony.owen@cbs.curtin.edu.au URL: http://aaee2008cbs.curtin.edu.au

24-28 November 2008, Global LNG - the Complete Supply Chain at Oxford, UK. Contact: Ms. Lesley Rigg, The Oxford Princeton Programme, 1st Floor, 59 St. Aldates, Oxford, OX1 1ST, United Kingdom. Phone: +44-1865 250 521 Email: info@oxfordprinceton.com URL: http://www.oxfordprinceton.com/search/coursedetails.asp?ID=318&PLP=LNG1%5CBGBR08

2-2 December 2008, Smart Metering - Gizmo or Revolutionary Technology? at London, UK. Contact: Jennifer Wiffen, TPN Manager, The Institution of Engineering and Technology, United Kingdom. Phone: 01438 465658 Email: jwiffen@theiet.org URL: www.theiet.org/smartmetering

3-5 December 2008, 28th USAEE/IAEE North American Conference: Penetrating Energy Frontiers at New Orleans, LA. Contact: David Williams, Executive Director, USAEE, 28790 Chagrin Blvd Ste 350, Cleveland, OH, 44122, USA. Phone: 216-464-2785. Fax: 216-464-2768 Email: usaee@usaee.org URL: www.usaee.org

20-21 January 2009, 29th Oil & Money Conference at London, UK. Contact: Juanine Stroebel, IHT, 40 Marsh Wall, London, E14 9TP, United Kingdom. Phone: 44-20-7510-5729. Fax: 44-20-7987-3463 Email: jstroebel@iht.com URL: http://ihtinfo.com/events

3-5 February 2009, One Live Wire at San Diego, Ca. Contact: Debbi Boyne, CMP, Conference Coordinator, Distributech Conference & Exhibition, 1421 South Sheridan, Tulsa, OK, 74112, USA. Phone: 918-832-9265 Email: dtechconference@pennwell.com URL: www.distributech.com

11-15 May 2009, Achema 2009 at Frankfurt, Germany. Contact: Conference Coordinator, Dechema e.V., PO Box 15 01 04, Frankfurt am Main, 60061, Germany. Phone: 49-0-69-7564-0. Fax: 49-0-69-7564-201 Email: achema@dechema.de URL: www.achema.de

21-24 June 2009, 32nd IAEE International Conference: Working Title: Energy, Economy, Environement: The Global View at San Francisco, CA. Contact: David Williams, Executive Director, USAEE, 28790 Chagrin Blvd Ste 350, Cleveland, OH, 44122, USA. Phone: 216-464-2785. Fax: 216-464-2768 Email: usaee@usaee.org URL: www.usaee.org

7-10 September 2009, 10th IAEE European Conference at Vienna, Austria. Contact: IAEE Conference Secretariat, IAEE, 28790 Chagrin Blvd Ste 350, Cleveland, OH, 44122, USA. Phone: 216-464-5365. Fax: 216-464-2737 Email: iaee@iaee.org URL: www.iaee.org

6-9 June 2010, 33rd IAEE International Conference at Rio de Janeiro, Brazil. Contact: IAEE Conference Secretariat, IAEE, 28790 Chagrin Blvd Ste 350, Cleveland, OH, 44122, USA. Phone:

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