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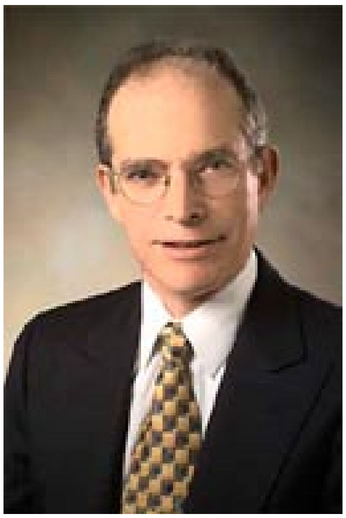
President's Message



Albuquerque, New Mexico: a chilly-but-sunny, sky blue January day in the foothills of the snow covered Sandia Mountains. A new year, a new beginning, and a new IAEE President: I can't tell you how honored and privileged I am to serve you in this role.

Tony Owen and his Council, supported by the Dave Williamses (Jr. and Sr.) have done a superb job in leading and managing our organization. During 2005 I hope to build on their successes, and as a famous chef often says, if I'm lucky, to help "kick it up a notch."

When I started in the energy economics business as U.S. Federal Trade Commission Staff Economist in the early 1970s, the Commission opened a "monopolization" anti-trust case against the top six U.S. oil companies. About the same time, with the U.S. under energy price controls, Saudi Arabia embargoed the U.S. and the Netherlands, world oil prices quadrupled, and the U.S. thought it could regulate its energy markets better than the markets themselves. Nuclear power was the poster child for clean, secure electricity. The U.S. imposed a host of new energy laws and regulations and a couple of Presidential initiatives, including Project Independence and the Moral Equivalent of War, to try to outsmart the market. By the 1980s, with a lot of hard work from many of us, and with oil prices falling from the current dollar high $30s into the current dollar teens, the policy-making community began to understand that oil markets were global and that energy markets worked, despite the best efforts of government and OPEC intervention. Much of the 1980s was spent, in the U.S. at least, dismantling the energy policy efforts of the 1970s. And following accidents at Three Mile Island and Chernobyl, and with high interest rates and capital costs, nuclear power became a pariah.

In the 1990s OPEC was in apparent disarray, energy supplies were abundant, prices were weak, and by the late 1990s, oil fell to the very low teens in current dollars. Folks began asking "what energy problem?", and in the U.S., cheap natural gas supplies even helped lead the drive for electricity industry restructuring. Environmental concerns overtook energy security concerns at national levels, with new environmental protection laws and regulations, such as the U.S. 1990 Clean Air Act Re-Authorization. This also became true at the international level. For example, the Intergovernmental Panel on Climate Change (IPCC) First Assessment Report (1990), lead to the Rio Declaration on Environment and Development (1992) and the UN Framework Convention on Climate Change, which entered into force in 1994 after it was ratified by the U.S. Congress and signed by President George H.W. Bush.

Now in 2005, there's an eerie sense of "déjà vu all over again," to quote a famous baseball catcher. Based on at least one set of published proven reserve estimates, six Persian Gulf countries and Russia together control about 70% of world proven oil reserves and about the same percentage of world proven natural gas reserves—and this region has no shortage of turmoil. Oil prices have risen from the low teens of late 1990s to fluctuate between $40 and the mid $50s per barrel.

(continued on page 3)

Editor's Notes

Jean-Thomas Bernard, Frédéric Clavet and Jean-Cléophas Ondo examine the Canadian government's program that puts a ceiling on the price of emission permits paid by industrial users and that allocates permits on the basis of output. They conclude that the approach has almost no effect on electricity production and trade flows and does little to reduce CHG emissions.

(continued on page 3)

HELMUT FRANK: AN APPRECIATION

It is with much sadness that I announce the passing of Helmut Frank on November 10, 2004. As many of you know, Helmut was the founding editor of our ***Energy Journal***, a pillar of its editorial board, an outstanding energy economist, and above all, a wonderful human being. We will miss him very much.

Campbell Watkins, Joint Editor of the ***Energy Journal*** and a long-time friend of Helmut's, has kindly put together the Appreciation we share with you below.

Arnie Baker

Helmut Frank was the founding editor of *The Energy Journal.* He tended and nourished the Journal during its first decade, a decade in which it swiftly established a reputation as the premier publication dealing with energy economics.

How did the Journal begin? A few years ago, Helmut acquainted me with some of the background. The IAEE, shortly after its birth in 1977, decided to sponsor a scholarly publication to achieve a goal of advancing and disseminating knowledge on energy economics. Sam Schurr, then president of the IAEE, wrote to Helmut in 1979, inquiring whether the University of Arizona would be willing to house the publication. The proposal was not without strings. Criteria included that the editor have sufficient time set aside to carry out the editorial function - an especially important condition - and that seed money be provided by the university to defray costs over the first two to three years.

At that time Helmut was director of the division of economic and business research in the College of Business and Public Administration. A faculty meeting was called and all present agreed the university should make a serious bid to land the Journal. But who was to be editor? As Helmut tells it, " . ..when it came to volunteering to serve as editor there was silence, though 1 felt al1 eyes were staring at me." However, Helmut was reluctant to step forward without relinquishing some of the responsibilities of his university post. Happily, that support plus provision of seed money was forthcoming from the university.

This positive response was welcomed by Sam Schurr who confirmed the selection of Helmut as editor of the Journal and the University of Arizona as the editorial headquarters. What was in Helmut's background that fitted him for the difficult task of founding the new Journal? He had the academic credentials, with three degrees from Columbia University. And his doctoral dissertation topic was, suitably, on the pricing of Middle East oil. This work led to publication by Praeger of his book Crude Oil Prices in the Middle East: A Case Study in Oligopolistic Price Behavior (1966).

Helmut's main academic research interests were, and remained, energy economics and policy. In that vein he had published on energy demand (especially natural gas), on oil and natural gas supply, and on U.S.- Canada energy trade. The latter topic was in line with some of his earlier interests in more general aspects of trade and the balance of payments. He also published on the tanker market, electricity and energy policy. In short, his academic work on energy was broad ranging, providing him with a grasp of the many facets of energy economics.

Helmut's experience also went beyond the academic confines. He had worked for W.J. Levy Consultants in the 1950s and early 1960s. This experience was also a fortunate attribute for someone founding the flagship Journal of an organization that was by no means an association of academics. The IAEE from its inception drew its membership from al1 walks - industry, government, institutions as well as universities. Moreover, Helmut had worked abroad, another useful aspect of his background for a publication intended to serve an international audience. His consulting studies and other activities saw him as a witness before the U.S. Senate, the Federal Power Commission and various other regulatory agencies. And he had served as a sergeant in the U.S. army, always useful if tardy referees and recalcitrant authors needed to be dragooned.

After Helmut's appointment as editor, Ed Erickson, then IAEE Vice President Publications (VPP), engaged a publishing company in Boston to handle al1 production and typesetting phases. The selection of papers, refereeing, publication decisions and copy editing were handled out of Tucson. A board of editors was appointed to assist in setting editorial policy. At the same time, Ed Erickson and subsequent IAEE VPPs continued to provide help and guidance.

The intention was to produce the first issue of the Journal by January 1980. This necessitated relying on papers from the first IAEE conference held in Washington in June 1979. The premier issue had to be in the publisher's hands by Labor Day. An assistant editor was hired, and by dint of prodigious efforts the deadline was met. *The Energy Journal* was off and running. It hasn't looked back.

Helmut presided over 40 regular issues and a number of special issues during his decade as the Journal's editor. He received an award at Bonn in 1985 for outstanding contributions to the Association, and a special IAEE Recognition Award in 1989 at Los Angeles to mark his retirement as editor. Helmut continued to be actively involved with the Journal in the position created for him as Founding Editor.

As then IAEE VPP I was the person presenting the award to Helmut in Los Angeles, and I used a natural gas analogy to describe his achievements, saying, "He had fulfilled a long-term firm contract, dedicated his reserves, shown reliable and consistent deliverability, and met peak demands." Helmut had a strong sense of duty, fairness and kindness; he was a source of encouragement for authors, especially beginners and those from overseas. He judged submissions by their content, not by the name or affiliation of the author; extra hours were put in to ensure things were done correctly at all stages of production. What also stands out is the enormously conscientious way he did the job. Lastly, and most importantly, Helmut never relaxed the standards, nor jeopardized the integrity, of *The Journal* – he set a fine example.

G. Campbell Watkins, Joint Editor, The Energy Journal

President's Message *(continued from page 1)*

Electricity restructuring has stalled in the U.S. and is glacially moving in the EU—such uncertainties cannot help but affect fuel choice decisions for power generation. The U.S. will again try to pass a comprehensive energy policy bill. Nuclear has risen from the dead, at least in some countries outside the U.S., and its prospects may be rising there as well. Natural gas markets are becoming increasingly globalized through cost competitive LNG, which will link electricity boiler fuel supply to world markets, as it was with oil in the early 1970s. Securing critical energy infrastructures, which are mostly owned by the private sector, has become a growing government concern. Russian energy policy, which seemed to be heading toward open markets has become somewhat confused. China's coal based electricity may inadvertently be sending mercury and other pollutants to the U.S. and other parts of the world. And the Kyoto Protocols to the Framework Convention are about to come into force without the U.S., despite strong pressure on the U.S. to join, and without developing countries, who are the key to successful long-term carbon emissions reduction.

All of this strangely suggests that government intervention in energy markets again may be on the rise; that long term climate change issues from greenhouse gas emissions may rank higher on global political/public policy agendas than nearer term energy security issues; and that much needs to be done nationally and internationally to help synchronize energy, environmental and economic public policies—at least to help them not work at cross purposes.

I believe our Association and your active participation are critical to these efforts. Increasingly the energy policies of the EU and its member countries, Russia and the CIS, Brazil and South America, North Africa, India, China and Asia, as well as the U.S., and of course the Middle East, will exert powerful influences not only within their own countries, but also on global energy and environmental markets. In a world of increasing globalization and competition, individual countries cannot afford to have energy-economic-environmental policies that cause their energy prices and energy security to be far out of line with the rest of the world. Our Association is an excellent vehicle to help share our individual and collective energy-economic-environmental learnings with each other and with public policy and private sector decision-makers around the globe, and in doing so, to help improve the quality of informed public policy and private sector energy-related decision-making.

We currently have national affiliates in 24 countries. In 2005 IAEE's flagship conferences will be held as follows: IAEE International Conference in Taipei, Taiwan (June 3-6); IAEE European Conference in Bergen, Norway (August 28-30); and the USAEE/IAEE Annual North American Conference in Denver, Colorado (September 18-20). I sincerely hope you will be able to join us for many of these; and if not, that you will actively contribute to our IAEE and Affiliate newsletters, as well as our distinguished *Energy Journal*.

In the future we hope to continue our geographic expansion to South America and other parts of Asia and Europe, to help strengthen existing national and regional affiliates, and to build new ones. We also hope to deepen our membership base both through students and universities, and through reaching out to experienced folks in industry and the public sector who are concerned about energy-economic and related environmental issues. Our success in energy-economics and in this national and international outreach will depend on you and your active participation.

For 2005 I would like to welcome back to IAEE Council Carlo Andrea Bollino and Andre Plourde, Tony Owen, Michelle Foss, Georg Erdmann, Majid Abbaspour, Einar Hope, Frits van Oostvoorn and new members Marianne Kah, Fatih Birol, Herman Franssen, Michael Kraus, and Hermann-Josef Wagner. It is also a pleasure to be working with newly elected IAEE President Jean-Philippe Cueille from the Institut Francais du Petrole. Together we will be revisiting and revitalizing our long term IAEE strategy and membership customer services. As a part of this effort, I would very much like to hear from you—your thoughts and concerns about our Association; what we're doing well and what we're not; what we need to do that we're not; and how we can be of better service to you as members and to the energy-economic-environmental community at large. Please send any thoughts you would like to share to Dave Williams at iaee@iaee.org during the year. He will collect them and forward them to me to feed into our efforts.

Let me say again what a great privilege and honor it for me to serve as your President this year.

With my very best wishes for a healthy and prosperous 2005.

Arnie Baker

Editor's Notes *(continued from page 1)*

Joseph Cavicchi and Andrew Kolesnikov provide a layman's overview of the problems many US wholesale electricity markets face regarding ensuring adequate future supplies. In particular they examine recently implemented and proposed administrative locational installed capacity markets in New York and New England and discuss various issues associated with using this approach to resolve future electricity supply adequacy concerns.

Robert Bergstrom reviews some of the lessons he has learned in working on big-ticket energy projects in and with transitional economies, primarily in Central and Eastern Europe and Central and Southern Asia, within the last decade and a half. He is optimistic that global investment can penetrate the barriers that older generations have created in these economies.

David McKeagen provides a note on measuring fuel economies and the effect on greenhouse gases.

Lorna Greening notes that uncertainty about the future plays a major role in the formulation of policy options. She focuses on hydrogen technology and analyzes how uncertainty affects projections of total costs. Through incorporating uncertainty into the decision process, low risk or risk-averse strategies may be identified in choosing a hydrogen development pathway.

DLW

28TH ANNUAL IAEE INTERNATIONAL CONFERENCE

Hosted by: International Association for Energy Economics (IAEE) & Chinese Association for Energy Economics (CAEE)

Globalization of Energy: Markets, Technology, and Sustainability

3-6 June 2005

The Grand Hotel, 1 Chung-Shan N. Road, Section 4, Taipei, Taiwan 104, ROC

Conference Themes & Topics

Keynote Plenary Session Themes: ***The Future of Energy: Solar Energy and Photovoltaics***

Plenary Session Themes: ***Energy Security, Cooperation, and Policy in the Pan-Pacific Rim***
Energy Business
Energy and Poverty in Asian Countries

Dual Plenary Session Themes:
- The Middle East Situation and Energy Security
- Regulation and Deregulation of the Energy Market
- Global Policy Options Dealing with GHGs Emission Control
- Rethinking of the Nuclear Energy
- Prospect for New Energy Technology
- Emerging Issues

Other Session Themes & Topics:

Prospects for Global Energy Development
- Global and Regional Energy Demand and Supply
- New Paradigm under the World Trade Organization
- Restructuring and Deregulation
- Inter-Regional Energy Security and Reliability
- Liberalization and Market Power
- Role of International Energy Suppliers

Prospects for Energy Technology Development
- Green and Renewable Energy Technology
- Conservation Know-how and R&D
- Fuel Cell and Hydrogen Technology
- Distributive Energy Systems
- Diffusion and Collaboration in Energy Technology

Sustainability
- Sustainable Energy Development
- Global Warming and Energy
- Energy and Pollution Control
- Nuclear Safety and Waste Disposal
- Rationality and Energy Selections
- Policy Options and Strategies

Individual Energy Sectors
- Coal
- Oil
- Natural Gas (including LNG)
- Electricity
- Renewable Energy and New Energy

Energy Efficiency and Energy Modeling
- Energy Statistics and Energy Efficiency Indicators
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Early Registration in Special Rates Deadline: 30 April 2005

The Grand Hotel Reservation in Special Rates Deadline: 6 May 2005

We are pleased to invite all of you to join the 28th Annual IAEE International Conference. There will be 10 plenary sessions and 42 concurrent sessions. For *online registration*, please visit the conference official website at: http://www.iaee2005.org.tw For *requesting registration form electronic file or paper copy*, please download from our website or email/write to the CAEE conference secretariat: **Yunchang Jeffrey Bor**, Ph.D., Conference Executive Director, Chung-Hua Institution for Economic Research (CIER), 75 Chang-Hsing Street, Taipei, Taiwan 106, ROC, Tel: 886-2-2735-6006 ext 631; 886-2-8176-8504, Fax: 886-2-2739-0615, E-mail: iaee2005@mail.cier.edu.tw

Please register early to grasp our special rates offering and mark your calendar for this important conference. You are kindly urged to register early, and book the airline flight and hotel as soon as possible because most of the hotels in Taipei will soon be fully booked due to the Dragon Boat Festival and the world's second largest Computex Exhibition held at the beginning of June 2005.

IAEE BEST STUDENT AWARD: US$1,000 cash prize plus waiver of conference registration fees. If interested, please contact IAEE headquarters for detailed applications/guidelines. **STUDENT PARTICIPANTS:** Please inquire about scholarships for conference attendance to iaee@iaee.org

TRAVEL DOCUMENTS: International delegates are urged to contact their consulate, embassy, or travel agent regarding the necessity of a obtaining a Taiwan Visa. Use CAEE contact information above to obtain a letter of invitation for the conference. We strongly suggest you allow plenty of time for document processing.

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FUTURE USAEE / IAEE EVENTS

Annual Conferences

June 3-6, 2005	28th IAEE International Conference Taipei, Taiwan Grand Hotel
August 28-30, 2005	8th Annual European Conference Bergen, Norway
September 18-21, 2005	25th North American Conference Denver, Colorado, USA Omni Interlocken Resort
June 7-10, 2006	29th IAEE International Conference Potsdam, Germany Kongresshotel am Templiner See

2nd CZAEE Annual International Conference December 8-9, 2005 • Prague, Czech Republic

Last year's 1st CZAEE Annual International Conference in Prague, Czech Republic, was met with great success and attended by more than 140 participants from 16 countries.

The 2nd CZAEE Annual International Conference will take place again in Prague on Dec. 8-9, 2005 and will focus on strategic issues on Critical Infrastructure Protection and Continuity Business Planning topics.

A Call for Papers announcement will be published in the May issue of the *IAEE Newsletter*. Please also keep posted to http://www.iaee.org/en/conferences/ for the most current Prague 2005 conference announcement.

IAEE Newsletter Disclaimer

Special Issue of *The Energy Journal* Available

DISTRIBUTED RESOURCES:
TOWARD A NEW PARADIGM OF THE ELECTRICITY BUSINESS

Editors: Adonis Yatchew and Yves Smeers

As electricity industries worldwide move toward restructuring, rationalization and increased competition, a variety of factors are combining to increase the prominence of distributed resource alternatives. This special issue examines issues relating to distributed resource alternatives in a world where electricity industries are undergoing restructuring.

Table of Contents:

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24th North American Conference
Washington, DC, USA, 8-10 July, 2004

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Canada – U.S. Electricity Trade and GHG Emissions Policies: The Situation in the North East

*By Jean-Thomas Bernard, Frédéric Clavet and Jean-Cléophas Ondo**

Summary

Canada has ratified the Kyoto Protocol while the United States, its main trading partner, has not. A major concern of Canadian industrial producers is the negative impact on competitiveness of programs designed to reduce greenhouse gas emissions (GHG). To alleviate this concern, the Government of Canada is proposing an approach that puts a ceiling on the price of emission permits paid by industrial users and that allocate emission permits on the base of output. We analyze how such a scheme would affect electricity production and trade among three Canadian provinces (Ontario, Québec and New Brunswick) and two U.S. regions (New England and New York), which are linked by large interconnections and which exchange electricity on other wholesale markets. We find that the Canadian government approach has almost no effect on electricity production and trade flows; so it is very effective at protecting the competitive position of electricity producers. However, it does little to reduce GHG emissions.

Introduction

After a protracted consultation process which lasted more than four years and which revealed conflicting regional and industry positions, Canada finally ratified the Kyoto Protocol in December 2002. Now Canada is committed to a 6% reduction of its greenhouse gas (GHG) emissions below the 1990 level over the first commitment period, from 2008 to 2012. According to Government of Canada estimates, this means that CO_2 eq. emissions[1] will have to decrease by 240 Mt or by 30% relative to the business-as-usual (BAU) scenario over the test period. In order to make explicit its intention to reduce GHG emissions, the Government of Canada published a plan that sets the guiding principles, the policy instruments and the specific targets by sector.[2] It claims that the measures that have already been launched will cause CO_2 eq. emissions to fall by 80 Mt.[3] The plan released in November 2002 presents policy actions and programs to lower further CO_2 eq. emissions by 100 Mt.[4] 55 Mt of this reduction are supposed to be realized by the large industrial emitters which are oil and natural gas production, electricity generation from fossil fuels (oil products, natural gas and coal) and a small group of heterogeneous industries,[5] According to BAU emission projection, the power generators share is about 20 Mt.

A major concern expressed by the Canadian industrial producers is the negative impact of such a policy on their competitive position in international markets. A cause of this concern comes from the fact that the Bush administration has decided not to ratify the Kyoto Protocol and that more than 80% of the international trade of Canada takes place with the United States. To address this concern, the Canadian plan contains measures to alleviate the burden that industries would bear. Two measures are of particular significance: first, no measure that costs more than \$15/tonne of CO_2 eq. should be undertaken by industries[6]. This sets a ceiling on the price of emission permits to be paid by the Canadian industrial users. Second, Canadian industries are not going to be asked to make CO_2 eq. emissions reduction that exceeds 15% of their emissions associated with the BAU scenario in 2010[7]. This means that the Canadian industries will receive free of charge 85% of the permits associated with their specific emission target.

The fact that the Bush administration has decided not to sign the Kyoto Protocol and that there is no plan in the United States as in signatory countries, does not mean that there will be no government program that makes a contribution to the objective of the Protocol. For instance, the New England states governors are committed to stabilize GHG emissions to their 1990 level in 2010 and to reduce them by 10% in 2020; New York State is considering the development of a regional GHG emission permit market for electricity producers that will encompass also the New England states and the PJM area.[8] Furthermore, it is possible that some standards will be set for electricity production from renewable sources. At this stage it is unclear what will be the end results of these policy initiatives; however, the time lag required to change the mix of electricity generation equipments leads to believe that their real effects around 2010 are likely to be minor.

The U.S. wholesale electricity market has been open to competition since January 1997 through FERC Order 888 which allows producers, local distribution utilities or any FERC licenced marketers to exchange electricity at market prices. Canadian electric utilities satisfied the reciprocity conditions imposed by FERC upon foreign applicants and obtained their FERC licences to participate in this new open wholesale market. Now there are wholesale electricity markets operating in New York and New England.[9] There were already significant electricity exchanges between the United States and Canada before 1997, mostly through long-term contracts; the structural change has tilted the balance in favour of instantaneous direct competition. In 2002, Canada exported 34.1 terawatt-hours (TWh) and the share of interruptible sales was 77.0%; it imported 20.8TWh and the share of interruptible sales is close to 100%. In value terms, exports were worth \$1837 million and imports \$1370 million[1.0] The provinces of Ontario, Québec and New Brunswick (N.B.) accounted for 59.0% of the exports and 96.0% of the imports.[10] The bulk of the exchanges of these three provinces is with New York and New England.

The purpose of this paper is to analyze the effects of the implementation of the Kyoto Protocol by Canada on the electricity production and exchanges between the three aforementioned provinces and their southern neighbors in

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[1] See footntoes at end of text.

the United States, i.e., New York and New England. Because of the time lag required to bring in service, new generating equipments, existing power plants are going to be a major factor in the implementation of the Kyoto Protocol at least toward the first commitment period, i.e., around 2010. Our aim is to analyze how interfuel substitution and trade could foster or impair the realization of the objective of the Kyoto Protocol, what are the effects on the output of Canadian electricity producers and what are the likely costs of implementing the Protocol.

The order of the presentation is as follows: in the first section, we describe the underlying analytical framework and we single out key features of the data that enter into the cost minimization problem which is assumed to represent the operations of the open wholesale electricity market. In the second section, we present and discuss the results. Toward this end, we build two scenarios: in the first scenario, which is considered to be our base case, we have free trade and no regulation on GHG emissions. The second scenario embodies the main features of the output base allocation of emission permits as currently proposed by the federal government, i.e., the $15/tonne price ceiling on emission permits and the 85% share born by the government.

Here is our finding: the Canadian government approach, which imposes a price ceiling on emission permits and which allocates emission permits on the base of production, has almost no effect on production and trade flows; it has also no effect on GHG emissions.

The Analytical Framework and Electricity Market Information

In order to study the effects of limiting CO_2 eq. emissions on electricity production and exchanges between the five regions, we use the 1998 data on load, available generating capacities, average fuel costs by type of generating equipment and interconnection capacities between the five regions. The year is divided into four uneven periods: Winter peak (300 hours), Spring (3930 hours), Summer peak (600 hours), and Fall (3930 hours). The stepwise representation of the load curve allows us to capture the specific role played by hydro power plants; although the latter can accommodate a fairly flexible production schedule, they are limited not only by their generating capacities like any other generating plants, but also by the amount of electricity that can be produced from the available water.

Under the two scenarios which are called respectively free trade and output base allocation of permits in Canada, we assume that all the available resources in the five regions are used to minimize the total fuel cost of serving the given seasonal load in each region, while taking into account the constraints related to generating capacities, interconnection capacities, available hydroelectricity and policies related to CO_2 eq. emission reduction. The results of the cost minimization problem of serving the given load yield the optimal use of the generating capacities in each region and the trade flows during the four periods of the year.

We now present a brief description of the data that enters into this cost minimization problem. Table 1 shows our stepwise representation of the load curve in MW within each of the five regions. Canadian regions have Winter peak demand due to electrical space heating while New York and New England have Summer peak load due to air conditioning. Altogether, the five regions have a Winter peak load.

Table 1
1998 Demand (MW)

Period	Québec[1]	Ontario	New Brunswick	New England	New York	Total
Winter (300 h)	34295	22330	3333	19800	24150	103908
Spring (3930 h)	20461	16087	1668	12428	16132	66776
Summer (600 h)	20461	21387	1668	22100	28960	94576
Fall (3930 h)	20461	16087	1668	12428	16132	66776

Estimated by the authors from North American Reliability Council (1998, 1999).

[1] For Québec, we use the 1999 data due to the 1998 ice storm. 2300 MW of generation for own use by private companies are added to arrive at Québec total demand.

The upper part of Table 2 displays the available generating capacities by region. Hydro generating capacity represents 41.7% of the total; this is due mostly to Québec where hydro power plants form 94.1% of its total capacity. Most of its hydro power stations are backed by reservoirs which are filled by spring runoff and which provide water for the rest of the year until the next cycle starts. In terms of relative importance, hydro generating capacity is followed by oil (24.0%), nuclear (14.5%), coal (11.1%), natural gas (6.4%) and other (2.2%).[12] We assume other generating capacities to be must-run units and their utilization rates are based on recent experiences. The last line of Table 2 shows the total electricity (TWh) that can be produced by the hydro power stations.[13] The 262.3TWh of hydroelectricity represent 42.6% of the overall electricity demand (616.03TWh) of the five regions in 1998.

Table 2
1998 Available Generating Capacity (MW)
and Hydroelectricity (TWh)

Type	Québec	Ontario	New Brunswick	New England	New York	Total
Hydro	37 996[1]	8 034	919	3 599	5 470	56 018
Nuclear	675	8 728[2]	680	4 365	4 981	19 429
Coal	--	7 797	570	3 311	3 262	14 940
Oil1	1596	2 302[3]	1 884	11 930	14 600	32 312
Natural Gas	37	1 803	--	1 858	4 959	8 657
Other[4]	90	334	511	1 599	469	3 003
Total	40 394	28 998	4 564	26 662	33 741	134 359
Hydroelectricity[5]	190.140[6]	39.818	3.000	4.380	24.930	262.268

Source (Québec, Ontario and New Brunswick) : Statistics Canada (1998a) and Statistics Canada (1994, 1995, 1996). (New England and New York) : U.S. Energy Information Administration (1994, 1995, 1996, 1998).

[1] Due to a long term contract, 5 428 MW from Churchill Falls in Labrador are included in Québec capacity.

[2] Total nuclear generating capacity is 13 864 MW. Bruce A (2 060 MW) and Pickering A (3 076 MW) nuclear power plants have been taken out of service. See Ontario Power Generation (2002).

[3] Oil or natural gas can be used as fuel.

[4] Geothermal, solar, wind and biomass.

[5] Average hydroelectricity production (TWh) in 1994, 1995 and 1996.

[6] 26.649 TWh from Churchill Falls in Labrador are included.

Table 3 shows the average fuel costs associated with the generating capacities of each region. Here is the overall increasing order of costs by generation type: hydro, nuclear, coal, oil and natural gas. However, there are some exceptions: natural gas average costs are less than oil average costs in Québec and Ontario. Furthermore, oil in New Brunswick (1884MW) has a lower average cost than coal in New England (3311MW). The increasing order of the average fuel costs is the main factor behind cost minimization.

Table 3
1998 Average Fuel Costs (¢/kWh)

Type	Québec	Ontario	New Brunswick	New England	New York
Hydro	0.00	0.00	0.00	0.00	0.00
Nuclear	0.18	0.23	0.18	0.18[1]	0.18[1]
Coal	--	2.07	2.35	2.68	2.20
Oil	3.86	3.22	2.37	3.15	3.02
Natural Gas	1.86	3.09	--	4.23	3.93

Source (Québec, Ontario and New Brunswick) : Statistics Canada (1998b).
(New England and New York): U.S. Energy Information Administration (1998).
[1] No data are available. We use the Canadian information.

Interconnection capacities (MW) between the contiguous regions appear in Table 4. Figure 1 shows the geographical layout of the high voltage interconnections which link the power grids of the five regions. Québec occupies a pivotal position and it has fairly large interconnections with all its neighbors. In general, the north-south interconnections of the Canadian regions to the U.S. power grids are larger than the east-west interconnections between the Canadian provinces. This is expected due to the seasonal complementarity of the power grids along the north-south axis. The size of the interconnections between the five regions can be considered to be large when they are compared to what exists elsewhere in Canada and in the U.S. Nonetheless, if we set aside New Brunswick which has much smaller generating capacities than the other four regions, we see that the size of the interconnections is relatively small when interconnection capacities are compared to peak demand in each region. This limits the role that competition from outside sources can play in each region and the extent that marginal costs can be equalized in the new deregulated wholesale market.

Table 4
2000 Interconnection capacity (MW)

From/To	Québec	Ontario	New Brunswick	New England	New York	Total
Québec	--	1 195	1 200	2 303	2 695	7 393
Ontario	550	--	--	--	2 325	2 875
New Brunswick	785	--	--	815	--	1 600
New England	1 670	--	815	--	1 600	4 085
New York	1 000	1 300	--	1 425	--	3 725
Total	4 005	2 495	2 015	4 543	6 620	19 678

Source (Québec, Ontario and New Brunswick): Canadian electricity association and natural resources Canada (1999).
(New England and New York): New York Independent System Operator (2000).

In order to keep the problem at a manageable scale without limiting unduly the validity of the analysis, we take as given the exchanges with power grids other than the five regions included in our study and they are set at their pre-1997 level. Ontario is a net exporter to Michigan and Minnesota, New Brunswick to Nova Scotia and Prince Edward Island, and New York is a net importer from PJM. The trade of flows with power grids outside the five regions are much smaller than the trade flows within the five regions.[14] .

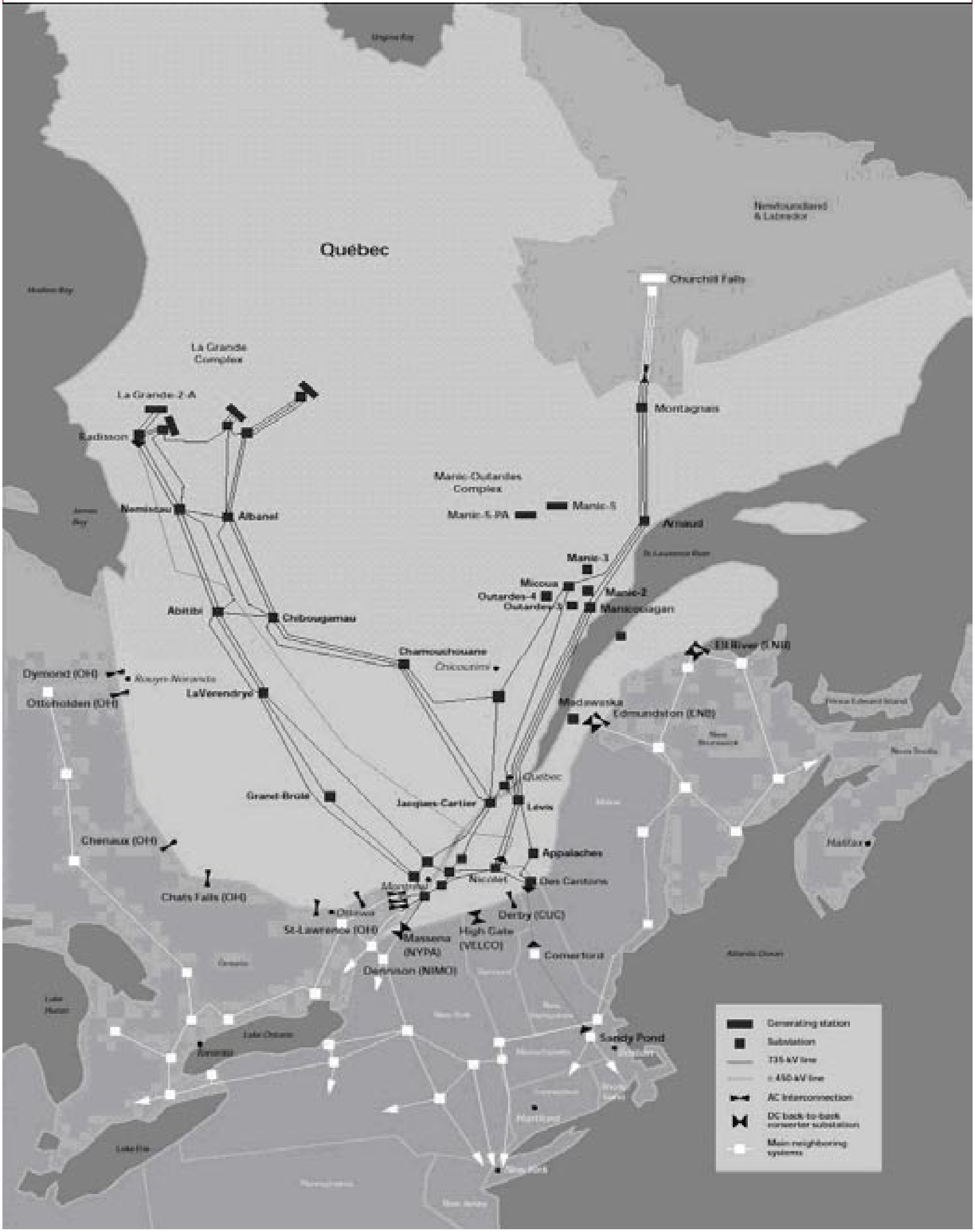
The commitment of the Government of Canada with respect to the Kyoto Protocol is to reduce the GHG emissions to the 1990 level minus 6%. Here are the CO_2 eq. emissions (Mt) that resulted from the 1990 electricity production of the three provinces: Ontario (27.4), Québec (1.1) and New Brunswick (6.5) for a total of 35.0.[15] In that year, electricity production emitted 40.8 Mt of CO_2 eq. in New England and 61.6 in New York for a total of 102.4.[16] In this study, we assume that the CO2 eq. emissions by fuel type (Mt/TWh) are: coal (0.974), oil products (0.778), and natural gas (0.511).[17]

Table 5
Production and CO_2 Emission: Free Trade

Region / Type	Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	(TWh)	($MtCO_2eq$)
Québec						
Hydro	35 327	21 177	21 814	21 177	190.14	0
Nuclear	675[1]	675[1]	675[1]	675[1]	5.91	0
Coal	--	--	--	--	--	--
Oil	0	0	0	0	0.00	0
Natural Gas	37[1]	37[1]	37[1]	37[1]	0.32	0.2
Other[2]	60	60	60	60	0.53	--
Total	36 099	21 949	22 586	21 949	196.90	0.2
Ontario						
Hydro	8 034[1]	4 146	8 034[1]	4 146	39.82	0
Nuclear	8 728[1]	8 728[1]	8 728[1]	8 728[1]	76.46	0
Coal	7 797[1]	6 461	7 797[1]	6 461	57.80	56.3
Oil	0	0	0	0	0.00	0
Natural Gas	0	0	0	0	0.00	0
Other[2]	131	131	131	131	1.15	--
Total	24 690	19 466	24 690	19 466	175.23	56.3
New Brunswick						
Hydro	919[1]	302	583	302	3.00	0
Nuclear	680[1]	680[1]	680[1]	680[1]	5.96	0
Coal	570[1]	570[1]	570[1]	570[1]	4.99	4.9
Oil	1 884[1]	1 729	1 448	1 729	15.02	11.7
Natural Gas	--	--	--	--	--	--
Other[2]	104	104	104	104	0.91	--
Total	4 157	3 385	3 385	3 385	29.88	16.6
New England						
Hydro	3 599[1]	145	3 599[1]	145	4.38	0
Nuclear	4 365[1]	4 365[1]	4 365[1]	4 365[1]	38.24	0
Coal	3 311[1]	3 311[1]	3 311[1]	3 311[1]	29.00	28.3
Oil	2 827	0	5 127	0	3.92	3.1
Natural Gas	0	0	0	0	0.00	0
Other[2]	1 155	1 155	1 155	1 155	10.12	--
Total	15 257	8 976	17 557	8 976	85.66	31.4
New York						
Hydro	537	2 867	3 730	2 867	24.93	0
Nuclear	4 981[1]	4 981[1]	4 981[1]	4 981[1]	43.63	0
Coal	3 262[1]	3 262[1]	3 262[1]	3 262[1]	28.58	27.8
Oil	14 600[1]	1 917	14 600[1]	1 917	28.21	21.9
Natural Gas	0	0	0	0	0.00	0
Other[2]	343	343	343	343	3.00	--
Total	23 723	13 370	26 916	13 370	128.35	49.7
Total	**103 926**	**67 146**	**95 134**	**67 146**	**616.03**	**154.2**

[1] Maximum generating capacity.
[2] Geothermal, solar, wind and biomass

Figure 1
High Voltage Interconnections



Results and Discussion

Scenario 1: Free Trade

Table 5 shows the use of generating equipments under free trade which is considered to be our base case. As is expected, hydro and nuclear power, which have zero or low fuel costs, are used to their full extent in all regions. These two sources have zero emissions and their 100% use means that no further GHG emission reduction can be directly obtained from them. However, hydro generating facilities are not operating at full capacity (MW) most of the time even if all available water is used; therefore, hydro resources can still be reallocated from one period to another period to accommodate some substitution toward sources which have lower emissions and in this way, they can make an indirect contribution to GHG emission reduction. Ontario has large coal fired generating facilities which have low average costs relative to other regions; so they are used to the fullest extent which is compatible with the available interconnection capacities. This is also the case of oil facilities in New Brunswick. Coal generating power stations in New England and New York are used at full capacity while oil facilities are the marginal generating sources. Except for Québec, which is a minor exception in this respect, natural gas power plants have relatively high fuel costs and make no contribution to the load in any of the other four regions.

Table 6
Origin and Destination of Electricity: Free Trade

From/To	Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	(TWh)
Québec Québec	33 572	19 126	19 298	19 126	171.98
Ontario	378	550[1]	378	550[1]	4.66
New Brunswick	0	785[1]	785[1]	785[1]	6.64
New England	0	0	0	0	0.00
New-York	344	0	0	0	0.10
Total	34 295	20 461	20 461	20 461	183.39
Québec Ontario	0	0	0	0	0.0
Ontario	22 515	16 591	22 275	16 591	150.52
New-York	0	0	0	0	0.00
Total	22 515	16 591	22 275	16 591	150.52
Québec New Brunswick	224	0	0	0	0.07
New Brunswick	3 342	1 785	1 785	1 785	16.10
New England	0	0	0	0	0.00
Total	3 566	1 785	1 785	1 785	16.17
Québec New England	2 303[1]	1 755	2 303[1]	755	15.86
New Brunswick	815[1]	815[1]	815[1]	815[1]	7.14
New England	15 257	8 976	17 557	8 976	85.66
New-York	1 425[1]	882	1 425[1]	882	8.22
Total	19 800	12 428	22 100	12 428	116.88
Québec New-York	0	1 069	984	1 069	8.99
Ontario	1 797	2 325[1]	2 037	2 325[1]	20.04
New England	0	0	0	0	0.00
New-York	21 953	12 487	25 491	12 487	120.03
Total	23 750	15 881	28 513	15 881	149.06
Total	103 926	67 146	95 134	67 146	616.03

[1] Maximum generating capacity.

Overall CO_2 eq. emissions (Mt) under free trade are higher than the 1990 level, i.e. 154.2 versus 137.4.[18] They are much higher in Canada, 73.1 versus 35.0, while they are lower in the two U.S. regions, 81.1 versus 102.4. The shift of CO_2 eq. emissions from the United States to Canada is caused by the low costs of coal facilities in Ontario and New Brunswick, and the low cost of oil facilities in the latter province and by the fact that 5136 MW (Bruce A, 2060MW and Pickering A, 3076 MW) of nuclear power in Ontario have been taken out of service.

Table 6 shows that congestion interconnections is fairly widespread; however, congestion is mostly associated with moving power into New England, either directly or indirectly through Québec and New York. The three Canadian provinces are net exporters while the two U.S. regions are net importers.

The upper part of Table 7 shows the marginal costs in each region during the four periods of the year. We can see that free trade does not lead to the equalization of marginal costs in the five regions due to the limits imposed by the interconnections. Québec and New York, which are located at the centre and which are linked by large interconnections, are free of congestion and hence they share the same marginal costs, that is 3.02¢/kWh. However, the imports into New England are limited by the congested interconnections during the Winter and the Summer peak periods and as a result, New England makes use of its high cost oil facilities at 3.15¢/kWh. Exports from coal facilities in Ontario during Spring and Fall and from oil facilities in New Brunswick during Spring, Summer and Fall are limited by congestion and the two provinces have lower marginal costs than New York and Québec during these periods.

Table 7
Marginal Cost (¢ / kWh)

Scenario/Region		Winter	Spring	Summer	Fall
Free trade	Québec	3.02	3.02	3.02	3.02
	Ontario	3.02	2.07	3.02	2.07
	New Brunswick	3.02	2.37	2.37	2.37
	New England	3.15	3.02	3.15	3.02
	New York	3.02	3.02	3.02	3.02
Output base allocation of permits in Canada and no U.S. action					
	Québec	3.02	3.02	3.02	3.02
	Ontario	3.02	2.29	3.02	2.29
	New Brunswick	3.02	2.57	2.57	2.57
	New England	3.15	3.02	3.15	3.02
	New York	3.02	3.02	3.02	3.02

Table 8 shows the fuel costs and the value of net exports in each region under free trade. The marginal cost of the importing region is assumed to be the price of the electricity, which is exchanged between two regions: this is what is expected under free competition. We can observe that altogether the three Canadian provinces have net export revenues of $1572 million and the bulk is directed to New England that has imports which are close to a billion. In summary, Canadian electricity producers should perform well under unfettered free trade due to their low operating costs. However, the negative side is the increase in GHG emissions.

Scenario 2: Output Based Allocation of Permits in Canada and No U.S. Action

The plan which has been proposed by the Government

Table 8
Profit Change and its Components ($ million)

Scenario	Québec	Ontario	New Brunswick	New England	New York	Total
			Fuel cost			
1	16.7	1 372.3	484.1	969.8	1 559.1	4 401.9
2	16.7	1 372.3	484.4	969.8	1 559.1	4 402.2
			Permit purchase			
1	--	--	--	--	--	--
2	2.5	843.9	244.4	--	--	1090.8
3	2.5	730.3	5.2	--	--	738.0
4	2.5	164.2	0.0	--	--	166.7
			Permit allocation			
1	--	--	--	--	--	--
2	2.1	717.3	207.7	--	--	927.1
			Net exports			
1	411.0	745.9	415.1	- 948.2	-623.8	0.0
2	411.0	745.9	415.1	- 948.2	-623.8	0.0
			Profit change			
1 / 2	- 0.4	- 126.6	- 37.0	0.0	0.0	-164.0
			Profit change (¢ / kWh)			
1 / 2	~ 0.0	- 0.1	- 0.2	0.0	0.0	--
			Relative to 1998 average price (%)			
1 / 2	0.0	1.0	3.5	0.0	0.0	--

[1] Free trade.
[2] Output base allocation of permits in Canada and no U.S. action.

of Canada to reduce the GHG emission in the industrial sector came out of the consultation process that led to the ratification of the Kyoto Protocol and the main feature is the allocation of emission permits on the base of actual output according to the following formula:

Number of permits = Physical output
x GHG emission intensity per unit of output
x Reduction factor.

The reduction factor is applied to bring the level of GHG emissions to the level which is deemed appropriate for the sector by the Government of Canada. For the oil and natural gas sector, the reduction factor is 85%. If we combine such a permit allocation mechanism with the $15/tonne price ceiling of emission permits, this means that the cost of a permit to the purchaser is reduced to $15 x 0.15 = $2.25/tonne since the purchaser of a permit needs to buy only 0.15 of a permit; the remaining 0.85 is provided gratis by the government. Given the CO_2 eq. emission intensity that we have adopted for this study, the modified permit price adds the following amounts to fuel cost (¢/kWh) in Canada: coal (0.22), oil (0.17), and natural gas (0.11). If we add these numbers to the average fuel costs as they are presented in Table 3, we can see that there are very few changes in the ordering of the costs: now coal (2.57¢/kWh) is more expensive than oil (2.54¢/kWh) in New Brunswick and coal (2.29¢/kWh) in Ontario is more expensive that coal (2.20¢/kWh) in New York. Our aim in developing scenario 2 is to analyze the effects of such changes relative to unfettered free trade; we assume that no action is undertaken in the U.S. regions to reduce GHG emissions in the electricity sector.

There is no change of total production in each region that comes out ot the Canadian policy toward GHG emissions. There is only one relative change by fuel type: electricity generated from oil goes up in New Brunswick with a compensating decrease of coal. The fact that coal production in New York is now cheaper than coal production in Ontario does not induce any change since coal facilities in New York were already fully used under free trade. The small substitution of coal by oil in New Brunswick brings emission down by 0.4Mt of CO_2 eq.; this is a very small change. Since there is no change in the total production by fuel type in each region, there is no change in the pattern of trade relative to free trade.

Table 7 shows the impacts of the $2.25 permit price in Canada on the marginal costs. The only change occurs in the off peak marginal costs of Ontario and New Brunswick. Since exports out of these two provinces are limited by interconnection congestion during these periods, there is no influence on the neighbours. The same point can also be seen in Table 8 which shows no changes in the values of net exports in comparison to free trade.

Except for the small increase of fuel cost in New Brunswick, the only significant change is the purchase of emission permits by Canadian producers at the net price of $2.25/tonne. In order to show the significance of the resulting profit change, we present two indicators in Table 8. The first indicator is the profit change per unit of sale within each region. The second indicator is the first indicator divided by the average price of electricity in each region in 1998. The motivation behind the second indicator is to assess how the price paid by the final user would need to change so that the profits of the producers are brought back to the level under free trade. To illustrate the information transmitted by this second indicator, let us consider the case of Québec which experiences no change of marginal costs, and yet its cost goes up due to its small electricity generation from natural gas. This is an infra marginal change which is not reflected in prices in competitive market. However it has a negative impact on profitability. In this particular case, it turns out to be very small. The negative impacts are somewhat larger in Ontario (+1.0%) and New Brunswick (+3.5%).

It should be noticed that the two U.S. regions which take no action to reduce GHG emissions, emit 81.1Mt of CO_2 eq. This is less than their combined emission level in 1990 (102.4Mt). The latter emission ceiling would not be binding for the U.S. electricity producers.

In summary, the approach proposed by the Government of Canada to shield the competitive position of Canadian industrial producers may turn out to be very effective; however the counterpart of this positive effect is that there is almost no reduction of GHG emissions. Total emissions of electricity producers in the three Canadian provinces are 72.7Mt of CO_2 eq. Since 15% are covered by permit purchase, the uncovered part is 61.8Mt, which is well above the 1990 emission level minus 6%, i.e., 32.9Mt. This would be a rather unsatisfactory situation. There are two ways to solve this problem and both impinge upon the competitive position of Canadian electricity producers. First, the Canadian government could lower its share of the emission permit price below 85% and thus increase the price of emission permits to Canadian electricity producers; second, it could impose some ceiling on the overall emission level. This second approach gives rise to difficult implementation issues: for instance, how to reconcile an output base allocation approach with an overall emission ceiling?

Conclusion

Canada has ratified the Kyoto Protocol and the United States have not. This is raising some concerns among Canadian industrial producers with respect to their competitiveness on the world market. To alleviate these concerns, the Government of Canada is proposing to introduce some safeguards on the costs born by large industrial GHG emitters. Two such safeguards are the price ceiling on GHG emission permits at $15/tonne and a favourable allocation of emission permits based on actual output. In this paper, we analyze the effects of such measures on the electricity production and exchanges between three Canadian provinces (Ontario, Québec and New Brunswick) and two U.S. regions (New York and New England). Electricity presents an interesting case because competition on the base of marginal costs is already well developed since FERC deregulated the U.S. wholesale electricity market in 1997. Using cost minimization of satisfying the load in each region as a representation of the operations of the wholesale electricity market, we find that the two safeguards suggested by the Government of Canada to shield the competitive position of Canadian industrial producers, i.e., emission permit price cap at $15/tonne and output base allocation at 85% of emission intensity, are very effective indeed in this respect. There is no change in production and trade flows. However, there is also little change in GHG emissions, which is the primary objective of the whole exercise. This is an unsatisfactory outcome which will require attention by the Government of Canada in the near future. Otherwise, Canada tax payers will have to pay a huge bundle related to GHG emission permits on the world market.

Footnotes

[1] CO_2 eq. emissions = CO_2 equivalent of GHG emissions.

[2] Government of Canada (2002).

[3] Including 30 Mt of CO_2 eq. in the form of sinks which are forest and agriculture accepted by the other parties to the Kyoto Protocol.

[4] The 60 Mt remaining gap will be addressed in programs to be announced later on.

[5] Mining, pulp and papers, chemical products, iron and steel, non-ferrous metals, cement and glass.

[6] This is a commitment by the Government of Canada for the first commitment period only. It is still possible that some industries may adopt measures that are more expensive than $15/tonne if they expect the emission permit prices to be above that threshold in future periods.

[7] The oil and natural gas producers have been told by the Minister of natural resources, The Honourable H. Dhaliwal (2002), that their reduction target will not represent more than a 15% GHG intensity reduction compared to BAU scenario during the first commitment period. See Nguyen (2003).

[8] Pennsylvania, New Jersey and Maryland.

[9] Such a market is also operating in Ontario since May 2002.

[10] Values are expressed in Canadian dollars.

[11] For an analysis of the effects of wholesale electricity market deregulation on the exchanges between Ontario, Quebec, N.B., New England and New York, see Bernard, Clavet and Ondo (2003).

[12] Geothermal, solar, wind and biomass.

[13] In order to remove some of weather randomness, we use the average hydroelectricity production in 1994, 1995 and 1996 prior to wholesale electricity market deregulation.

[14] See Bernard, Clavet, and Ondo (2003).

[15] Canadian Electric association and Natural Resources Canada (1991)

[16] http://www.eia.doe.gov/cneaf/electricity/st_profiles (1990)

[17] Gagnon (2000).

[18] Bernard, Clavet and Ondo (2003) estimate that the wholesale electricity market deregulation adds 4.3Mt of CO_2 eq. emissions.

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Ensuring the Future Construction of Electricity Generation Plants: The Challenge of Maintaining Reliability in New U.S. Wholesale Electricity Markets

*By A. Joseph Cavicchi and Andrew Kolesnikov**

Introduction

Several independently-operated, federally regulated, hourly wholesale electricity markets have been established in the U.S. during the last several years. Driven by the U.S. Federal Energy Regulatory Commission's (FERC) landmark 1996 regulatory order providing open access to the U.S. high voltage transmission network, various regions embraced the opportunity to form sophisticated, internet-based trading platforms that produce transparent hourly spot prices for wholesale electricity supplies. Concomitantly in most regions where these markets were introduced, significant investments in new, high-efficiency, low-emission electricity generators have occurred. These investments flooded the marketplace with excess supply of electricity generating capacity, quickly revealing weaknesses in the underlying market structures and resulting in documented under-compensation of generating capacity clearly required to maintain system reliability. The recognition that market modifications must be considered has resulted in numerous FERC proceedings focused on resolving the problem before a crisis ensues.

At the time restructuring was initiated it was understood that future investment was an important issue, but energy markets were expected to produce accurate price signals, and simply formulated capacity markets were expected to value facilities that were infrequently operated. Although much investment occurred at the onset of restructuring in many parts of the U.S., expectations associated with how the markets would function were not realized. This has become a pronounced problem during the current period of excess supply in many regions, but the time when more generation capacity will be required is rapidly approaching, driving the urgency to modify existing wholesale market structures.

Without delving into the myriad details associated with short-term wholesale electricity market design in the U.S., it is well understood that the combination of bid mitigation systems, designed to thwart the potential exercise of market power, and so-called reliability must-run contracts results in electricity market-clearing prices that undervalue electricity generation capacity in certain geographic regions. Usually these particular geographic areas are sub-regions of larger areas encompassing the operational footprint of a wholesale market.[1] It is within these sub-regions that the under-compensation, price signaling problem is most pronounced. Where we would expect the market system to reveal the value of generating capacity to investors, it does not, requiring the market operator to scramble to either support aged resources or acquire new resources in order to maintain system security and reliability. This observed approach to maintaining short-term system security, and ensuring long-term generating capacity adequacy, was not envisioned when these markets were put in place.[2]

At the same time energy prices have been suppressed, the initially constituted capacity markets[3] have been based on vertical demand curves that have proven to be a poor approach to pricing capacity. These initial market structures have been developed using the classic approach for defining a reliability standard: the amount of generation capacity available to the system should be adequate to ensure that only one major outage occurs every ten years.[4] Because there is limited ability for consumers to reduce demand in response to high prices (not to mention poor price revelation to consumers overall), the one-day-in-ten-year standard currently sets the establishment of generation capacity level throughout the U.S. regional electricity markets. Thus, capacity market minimum quantities have been established using this reliability standard. Simply stated, a generation quantity is set at some percentage above measured or forecasted peak demand (typically 12-18% above), and this amount is defined as the total amount of generation capacity required throughout a region to ensure reliable operation of the electricity system (resulting in the quantity which defines the vertical demand curve). System buyers responsible for serving consumers are required to purchase an amount of capacity based on peak obligations and face financial penalties if they do not purchase enough; generators either sell capacity bilaterally or receive revenues from auctions administered by system operators that ensure system buyers meet their obligations.

The vertical demand curve has been characterized as having two distinct undesirable characteristics. First, auction prices are volatile: whenever system capacity is above or below the set quantity, prices either shoot up to penalty levels, or decline to nearly zero. And second, when capacity is in, or near to being in, short supply, there can be opportunities for sellers to withhold supply and drive up prices. Moreover, the combination of total system excess supply and sub-regions where capacity is in short supply creates opportunities for buyers in some instances to realize preferential pricing by free-riding on the system.[5] Thus, suppressed energy pricing and unworkable capacity markets have resulted in observable inadequate remuneration for various generation facilities.

The resolution of these problems will not be simple. The market operator cannot force the construction of generating capacity when needed,[6] and buyers of generating capacity will employ all means possible of limiting expenditures for reliability, given its costs are not always easy to allocate equitably across system users. Moreover, generating capacity can often provide reliability and security services over fairly wide geographic regions, while consumers are in many instances represented by several utilities (load serving entities (LSE)) that are not subject to consistent regulatory frameworks, further complicating cost allocation issues. The

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[1] See footnoes at end of text.

existence and urgency surrounding implementing solutions to these problems cannot be underemphasized.

Theoretical Considerations for Ensuring that New and Existing Capacity Receive Remunerative Compensation

Electricity market pricing theory offers two possible methods of correcting the current pricing problems: value-of-lost-load (VOLL) pricing, or setting out minimum acceptable quantities (as described above). In a market modeled after the classic value-of-lost-load design, spot energy prices during times of tight supply are designed to mimic the consumer's marginal willingness to pay for electricity by allowing him to make the optimal trade-off between reliability and cost. As supply and demand edge closer together, prices spike, reflecting the high willingness to pay in order to avoid having to shed load. In reality, the absence of real-time metering precludes load from self-adjusting to the current prices; therefore, whenever power shortages are imminent, the market operator must artificially set the spot price to either an arbitrarily defined cap or an offer limitation, usually unrelated to the value of lost load. This value (often considerably less than VOLL estimates) can exceed average prices significantly and is a way of providing additional inframarginal rents to cover fixed costs, but has clearly been insufficient to compensate a generator that is typically marginal. Although, ignoring risk and market-power considerations, ideal VOLL pricing should induce a level of investment in generating capacity, which ensures a socially optimal level of reliability.[7]

However, serious flaws hamper a VOLL market design. First, since the market is not capable of determining the value of lost load by itself, VOLL must be set administratively. The difficulty of estimating the value of lost load leaves significant room for error, resulting in over- or suboptimal investment in capacity as well as either more violent or more frequent price spikes in the short run.[8] Second, setting spot price to VOLL levels whenever capacity drops below an amount necessary to ensure peak demand is satisfied produces a virtually vertical energy demand curve. Such market structure augments investors' risk premiums, which are, in turn, passed on to end users in the form of higher rates. Thus, VOLL pricing exposes consumers to unpredictable and costly price swings, making it a highly unattractive choice from a political standpoint. Third, since peaking units must rely on being paid the value of lost load during periods of shortage in order to recover their fixed costs, and since shortage hours are few and far between, fixed-cost recovery is highly uncertain. In addition, the number of shortage hours may fluctuate from year to year, depending on many random factors such as weather, availability of generating resources, and the status of the transmission network, which will cause under-recoveries in some years and over-recoveries in others. Such unpredictability with respect to cash flows will surely prompt investors to demand higher risk premiums, which will ultimately be passed down to consumers through higher prices. Finally, the inherent price volatility is further exacerbated by incentives to exercise market power. The lack of real-time metering prevents consumers from shedding load voluntarily whenever spot prices rise, rendering the short-run demand curve very inelastic. Therefore, as peak load approaches the level of operational installed capacity, generators have an increased incentive to withhold their resources and push the prices up even further. Together these shortcomings make VOLL pricing unattractive to regulators, and as we describe above, anything remotely resembling it has been eliminated due to concerns associated with the exercise of market power.

Thus, given the unattractiveness of VOLL pricing, an emphasis has been placed on setting an amount of generation quantity deemed sufficient to ensure reliability. By electing to set quantity, market designers and system operators then face the problem of how to ensure that the set quantity is available in the marketplace. As we describe above, the initial approach has been to use a vertical demand curve for capacity, as opposed to, say, a uniform price paid to all capacity, or instituting a system of individual payments made to certain generators required to maintain reliability in subregions. As the vertical demand curve for capacity has been unworkable, there has been a move underway to introduce an administrative downward-sloping demand curve to price generation capacity. Currently, this approach is in favor, although there is limited experience with the proposed market structure and considerable debate surrounding the potential success of the new approach.[9] When considered more generally, the problems associated with trying to create a regulated administrative market, such as this, have often been faced by policymakers.

Before examining in more detail the extant solutions being embraced to resolve the capacity payment problems, it is instructive to consider a theoretical paradigm developed to inform the process of deciding whether the control of price or quantity will create the most efficient outcome in those situations where an isolated economic variable (in this instance, reliability via capacity amount specification) needs to be regulated. A seminal work on this topic is Martin L. Weitzman's "Prices vs. Quantities."[10] The motivation of this work was the evaluation of the question of whether the control of pollution was better achieved by establishing pollution emission standards, or by setting pollution taxes. Over the past 30 years, we have seen the U.S. often elect the former approach, although it has not been a simple proposition to determine the most efficient method.[11] Thus, considering a framework within which the reliability assurance question can be considered is useful.

In the case outlined by Weitzman, he considers explicitly the difficult decision of determining whether quantity or prices should be used as planning instruments. He suggests a modeling framework wherein the decision is cast in the context of a trade-off between the social benefits and costs of one policy approach over another. He envisions a downward-sloping marginal benefit curve (analogous to the capacity demand curve) and an upward-sloping marginal cost curve (analogous to the capacity supply curve). He then proceeds to derive a so-called coefficient of comparative advantage that can be used to draw inferences on whether setting quantity or price is a better planning approach.[12] His results provide interesting insights applicable to the capacity-planning dilemma facing wholesale electricity market designers.

In particular, Weitzman shows that the slopes of the demand and supply curves will significantly affect the ability of the chosen policy instrument to perform efficiently. For example, he explains that, depending upon the magnitude and sign of the coefficient as determined by the slopes of the demand and supply curves, it is possible to establish whether price or quantity control will be a better planning approach. His primary findings tell us that when demand is steeply sloped (the benefit function is sharply curved), or the supply curve is nearly flat, it is better to control quantity. Conversely, when demand is elastic (the benefit function is near to being linear), the price control mode is relatively more attractive. As he explains, this is because the marginal social benefit is approximately constant in some range such that naming a price is more optimal, assuming limited cost uncertainty. Finally, if marginal costs are very steeply rising around the optimum—i.e., the supply curve is steep, as can be the case with fixed capacity—there is not much difference between controlling price and quantity. He suggests that in this situation, "non-economic" factors should play a prominent role in determining whether to control price or quantity. Generally, he finds that quantity control tends to be the less damaging approach to resolving this problem when facing uncertainty. Nonetheless, given that the capacity demand curves described herein are developed purely on the basis of expert opinion, the question of the appropriate shape certainly arises.[13]

Finally, when we examine the approaches taken to resolve this problem on a world-wide basis, we see that price is often the planning instrument of choice. For example, both Argentina and Colombia employ a fixed-capacity price paid to all capacity on the system that meets certain standards. Additionally, the U.K. has experimented with setting price, as opposed to quantity. Thus, although we limit our review herein to quantity-based planning standards where the shape of the demand curve is established administratively to achieve certain objectives, it may be the case that we are only beginning to develop an understanding of how to most efficiently approach the resolution of this problem.

Current U.S. Solutions to the Capacity Payment Dilemma: Locational Installed Capacity (LICAP) Markets

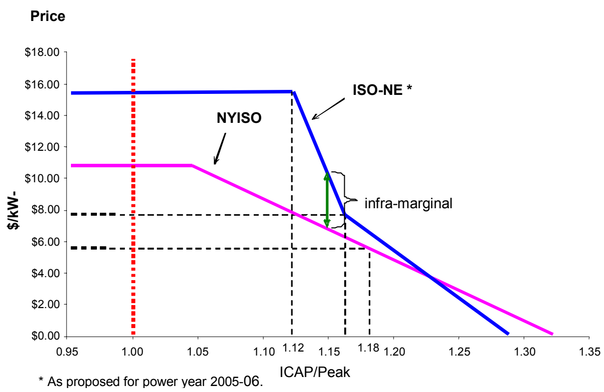
Given the problems that resulted when relying on capacity markets characterized by single vertical demand curves, there has been a significant effort placed on introducing price-quantity pairings—downward sloping demand curves—as a means of resolving the originally experienced problems. As we describe above, this is akin to making the policy decision to set quantity, and then proceeding to define the benefits function so as to achieve additional pricing objectives found to be desirable. Notwithstanding the limited experience that currently exists through the use of this approach, much effort has been expended by New York and New England to develop capacity demand curves that can be applied locationally (i.e., to sub-regions) as a means of setting prices based on desired quantities, and then stepping back and observing if investment is forthcoming in sufficient amounts to meet the desired reliability standard.

Generally, these newly constituted LICAP markets are designed to allow all generators, in particular peaking units, to recover their fixed (carrying) costs through the combination of energy-market rents and capacity payments. Additionally, they are formulated to place greater value on marginal capacity, leading to higher levels of reliability, which in turn would reduce the incidence of price spikes and lower the overall cost to consumers. Capacity prices are determined by the intersection of the short-run supply curve and the LICAP demand curve. In general, the LICAP demand curves are characterized by a flat high-price portion at low levels of installed capacity, designed to spur investment and bring installed capacity levels back up, and a downward sloping portion until prices hit zero at considerably higher levels of capacity, aimed at sending a retirement signal to the least efficient generators and reducing capacity down to the level of optimal reliability. LICAP demand curve designers define the price-quantity pairings for the curves such that an optimal level of investment in generating capacity occurs, while providing long-run prices that allow the marginal generator to recover its fixed costs.

The construction of a LICAP demand curve proceeds by first estimating two key inputs—the benchmark cost of capacity (BCC), previously called the cost of new entry, and the objective capability (OC) for the sub-region or zone in question. (OC is the amount of capacity necessary to meet forecasted demand.) BCC represents the annual fixed cost of the benchmark generator (either a frame or aero-derivative gas turbine peaking unit), which has the lowest fixed cost per megawatt of capacity and the highest variable costs. It is therefore typically the marginal generator that, during times of peak loads, sets the energy price in a market and earns the lowest infra-marginal rents. Thus, absent capacity markets, the benchmark generator systematically under-recovers its fixed costs and, assuming the decision rests solely with the generator, is driven out of the market. Under a LICAP market design, the price of capacity will hopefully hover close to the estimated BCC (EBCC) when the level of installed capacity provides adequate reliability, allowing the benchmark generator to recover its fixed costs and preventing it from exiting the market. Since any additional installed capacity would depress the LICAP price to below the EBCC, new generating units are discouraged from entry, thereby leading to an optimal long-run equilibrium level of installed capacity and a price equivalent to EBCC. OC, on the other hand, is the minimum acceptable level of installed capacity, the determination of which has been practiced by engineers for decades.[14] LICAP demand curves are defined by combining the appropriate EBCC and OC values, and then shaping the curve using expert opinion.

A LICAP market design using the demand curve described above has already been implemented in New York (by the New York ISO (NYISO)), while a similar LICAP market design proposed by ISO-NE is being reviewed by the FERC with the expectation that it will be put in place by January 1, 2006. At the same time, the PJM Interconnect is actively developing a reliability pricing model that also incorporates a capacity demand curve. Thus far, New York and New England provide excellent examples of two different approaches for drawing the capacity demand curve. Figure 1 portrays both New York's and New England's demand curves for power year 2005-06.[15]

Figure 1
LICAP Demand Curves, NYISO vs ISO-NE



The two LICAP demand curves display some similarities and some differences. In contrast to the pre-LICAP and VOLL designs' abrupt drop-off in the marginal value of capacity whenever it exceeded the required minimum, both New York's and New England's curves provide for a gradual decline in prices at above-optimal levels of LICAP, resulting in a less volatile and potentially more predictable stream of payments to generation owners, as well as hopefully more stable retail prices and sustained reliability. Both curves are designed to allow the marginal generators to recover their fixed costs, though the recovery mechanisms differ, and thus the NYISO's and ISO-NE's demand curves are not directly comparable. In New York, the price of capacity, as determined by the height of the demand curve at each particular value of LICAP, coincides with the actual capacity payment, and is calculated as the difference between the estimate of annual carrying costs of a new gas-fired combustion turbine and the estimate of the expected net revenues that a new combustion turbine would earn per year by selling into the energy and ancillary services markets.[16] While NYISO's demand curve determines the monthly capacity payments, ISO-NE's curve intersects supply at a conceptually different level. In New England, capacity payments are calculated as the difference between the LICAP price, as determined by the demand curve, and peak energy-market rents (PER),[17] and as proposed are distributed to eligible generators who made themselves available during shortage hours.[18] Because LICAP payments are reduced by price increases in the energy market, suppliers would lose as much in capacity payments as they would gain in energy rents should they choose to withhold their generation plants. Therefore, despite the fact that its demand curve incorporates energy rents, ISO-NE's proposal preserves the market-power mitigating characteristics of LICAP markets.[19] Moreover, it circumvents the difficulty and inevitable imprecision of estimating future infra-marginal rents by netting them out from the demand curve after the fact. This conceptual difference in the construction of NYISO's and ISO-NE's demand curves accounts for the significant price level discrepancy apparent upon initial comparison.

Table 1 presents a comparison of various aspects of the LICAP markets in operation in New York, and as proposed for New England. First, demand curve parameters vary as a function of LICAP zones. The definition of the zones is primarily based on system transmission limitations which require the ISO to use distinct operational guidelines to maintain reliability. Thus, the intention is that each LICAP zone be a geographic area where an incremental change in installed capacity would have a significantly different impact on reliability when compared to another area and, consequently, should be compensated differently. In New England, for instance, LICAP zones were initially designated according to the "currently-defined load zones in the NEPOOL Control Area."[20] As outlined in Table 1, ISO-NE has proposed five LICAP zones, compared to NYISO's three. There are suggestions that the loss-of-load-expectation (LOLE) should be the sole basis for the establishment of LICAP zones.[21] As such, separate zones should be created only if the installed capacity located there drops to levels insufficient to ensure a LOLE of one day in ten years, increasing capacity payments and thereby incenting new investments, and promptly eliminated as soon as new capacity brings reliability back to the required standard. However, this approach fails to recognize the fact that, in addition to transmission limits as well as other historical factors, new plant construction costs also tend to differ (in some instances significantly) among the currently established zones, a fact that is reflected by the zone-specific EBCC estimates.[22] Without accounting for these cost differences, there would constantly be an imbalance, as LICAP markets would always be over-compensating some generators and under-compensating others.

Table 1 also shows that another key difference between New York and New England LICAP markets lies within the market-clearing methodology. New York uses a nesting approach to clearing its markets. The NYISO administers monthly sequential locational installed capacity auctions, with the Long Island and New York City zones clearing an amount equal to locational sourcing requirements prior to running a larger regional market which then determines capacity prices for rest-of-state (the third New York zone) as well as that capacity that will be considered imported into New York City and Long Island. On the other hand, ISO-NE's proposed LICAP markets will clear all five zones simultaneously. This means that in ISO-NE, the amount of capacity that will be considered as imports into the various zones from rest-of-pool is determined by an optimization model and is limited to pre-defined capacity transfer limits between zones. Practically this means that in New England intra-regional supplies offering to deliver into constrained zones face a vertical supply curve, while in New York they face a sloping demand curve. Although these market clearing system approaches differ, and can result in different short-run prices, it is not expected that the revealed pricing should vary considerably over the long run.

Table 1
Key Characteristics of LICAP Markets in New York and New England

	New York[a]	New England
LICAP zones	NYC, Long Island, Rest of State	Maine, NEMA, SWCT, Rest-of-CT, Rest-of-Pool
Market-clearing methodology	Nested [b]	Simultaneous
Objective Capability (% above peak load)	18% [c]	12%
Break-even level of LICAP (% above OC)	0%	3.8% [d]
Zero-price level of LICAP (% above OC)	12% [e]	15%
Infra-marginal rent adjustment	Ex-ante	Ex-post

Note: LICAP and OC refer to locational installed capacity, and objective capability, respectively.
[a] The curves in NY are phased in, starting in 2003, in order to ameliorate rate impacts.
[b] NYISO administers sequential centralized monthly spot market auctions, whereby capacity in NYC and Long Island clears prior to Rest-of-State.
[c] Locational ICAP requirements in NYC and Long Island for power year 2004-05 are 80% and 99% of objective capability, respectively.
[d] The "target" level of ICAP in New England, the historical average level of capacity relative to OC, is numerically identical to the minimum requirement and break-even levels of ICAP in New York (1.054*1.12 is approximately 1.18).
[e] 18% in NYC and Long Island.

Although both New York and New England define objective capability as the level of installed capacity that ensures a LOLE of no higher than one day in ten years, the minimum required amount of capacity above forecast peak load differs between the two markets.[23] As Table 1 shows, the New York State Reliability Council (NYSRC) requires that installed capacity in the state exceed its peak load by 18%, while New England sets the region's minimum requirement at 12% above peak load. Since the installed capacity values on both demand curves were originally measured as a multiple of objective capability, the comparison of the two designs becomes more complicated. Therefore, in order to find a common denominator for the measure of capacity on the x-axis, the objective capabilities were converted back to peak loads in Figure 1. However, in order to preserve the curves' key parameters as they were originally defined by the ISOs, Table 1 lists them in terms of the minimum requirements.

Table 1 also shows that the New York and New England LICAP markets offer conceptually different levels of compensation to the owners of installed capacity. Whereas the marginal (benchmark) generator in New York breaks even whenever it brings the overall level of capacity to the required minimum, New England allows an additional 3.8 percent above objective capability. In effect, the break-even points in New York and New England then lie at 18 and 16 percent above peak load, respectively.[24] Similarly, the zero-price levels of LICAP, defined as 12 percent above OC in New York and falling at 15 percent above OC in New England,[25] correspond to 32 and 29 percent margins above peak load, respectively.[26] These differences can be seen in Figure 1.

Table 1 also shows the source of an obvious difference between the two curves plotted in Figure 1; the kink in ISO-NE's proposed demand curve. The kink occurs at the break-even level of installed capacity, as described above, and divides the downward-sloping portion of the curve into two segments. The left segment, by design, has a slope that is three times steeper than the slope of the right segment. Dr. Steven Stoft, who is responsible for the design of ISO-NE's proposed LICAP demand curve, argues that a steeper slope at close-to-deficient levels of installed capacity is necessary in order to send a stronger signal to investors and avoid shortages. Because "[t]he cost of too much installed capacity is considerably less than the cost of too little,"[27] the 3:1 slope ratio is justified. The value of capacity at the kink is calculated such that, assuming that the distribution of installed capacity levels maintains its historical standard deviation around the "target" level,[28] actual installed capacity falls below objective capability in only about 15 percent of years.[29] Thus, we see clearly how expert opinion leads to different demand curve parameters as well as differently shaped demand curves.

Lastly, as already discussed above, the price of locational installed capacity in New York, unlike in New England, has already been adjusted for infra-marginal rents. In general, as available capacity resources dwindle, energy and ancillary services' markets tighten, causing the prices to rise and, consequently, the rents that the generators earn by selling into these markets to increase. Conversely, as available capacity becomes more abundant, energy and ancillary services' markets loosen, leading to lower energy prices and lower infra-marginal rents. Recognizing this link between the energy and the capacity markets and the fact that generators must recover their carrying costs through a combination of rents from both markets, ISO-NE's demand curve is steeper than NYISO's at low levels of installed capacity and flatter at high levels. Thus, ISO-NE avoids the difficult estimation of infra-marginal rents by subtracting the actual rents from the LICAP price ex-post.[30] Thus, again expert opinion results in a significant difference in how capacity payments will account for inframarginal rents.

Conclusion

We clearly continue to be in a transitional mode characterized by a general lack of consensus on the appropriate policy choices to make to ensure reliability. Current policy on how to ensure future electricity system reliability in some regions of the U.S. is focused on establishing administrative LICAP market structures to value and hopefully cause, a predefined amount of generation capacity to be constructed. The ability of the new wholesale electricity markets in the Northeastern and Mid-Atlantic U.S. to signal the need for this next wave of generation investment is largely dependent on how well these new LICAP markets perform. Those investors that made past decisions based on expectations that markets would provide certain revenues will not be so willing to invest without assurances that capacity will be valued appropriately going forward. Although we expect that over the long run capacity will be compensated primarily via mid-term contracts, capacity markets will provide important signals as to the long-run marginal price of capacity. If we are to rely on administratively determined demand curves, we must be satisfied that they are shaped properly, and that there is true competition among those suppliers that offer capacity in the auctions. Currently it is clear that expert opinions differ on how to define and shape the demand curve in order to fulfill the reliability objective. As we can see from the curves, these differences will have an impact on capacity payments and thus expectations on the value of capacity in the future. In the near term it is imperative that LICAP markets send good price signals, as we cannot afford delays in needed future investments.

Footnotes

[1] For example, in New England the independent system operator (ISO-NE) has identified Southwest Connecticut as a problematic sub-region. In New York, both New York City and Long Island require separate consideration to ensure adequate capacity is available to meet demand. All these sub-regions are characterized by limited import capability, and in some instances are areas where siting new generation or transmission facilities is complicated both environmentally and technically.

[2] Although we understand that in some instances transmission system additions may resolve these observed problems, there nonetheless continues to be a fundamental problem with the current market structures when capacity shortages do not result in increased compensation to generating facility owners.

[3] At the time when independent system operators began administering wholesale electricity markets in the U.S., New York's, New England's, and Pennsylvania/New Jersey/Maryland's (PJM) ISOs each included capacity markets that were based on vertical demand curves. New York replaced its initial capacity market in 2003, New England is in the process of replacing its capacity market, and PJM is actively debating a so-called reliability pricing model to replace its capacity market.

[4] This refers to the bulk transmission and generation system as opposed to the lower voltage distribution system that will often experience weather induced outages.

[5] Initially constituted capacity markets had attributes that resulted in capacity being akin to a public good when it was in excess supply. Thus, consistent with the classic characteristic of a public good—non-exclusivity—buyers in all locations were able to take advantage of excess supply wherever it was located on the system. This problem was able to arise because generators have been required to offer their capacity in order to be eligible for capacity payments. Seriously limiting generators' ability to remove supply from the market led to capacity often resembling a public good.

[6] Of course, it is possible for the market operator to solicit supplies and make contractual obligations to buy such supplies, although taking a position in the market is completely contrary to the idea that market operators shall be independent and only provide a means for buyers and sellers to meet and transact anonymously.

[7] Stoft, Steven, *Power System Economics: Designing Markets for Electricity*, Piscataway, NJ: IEEE Press, 2002, at 159.

[8] The assumption is that regulators will eventually arrive at the correct level of VOLL by trial and error, spawning the desired level of investment in the long run.

[9] ISO-NE's proposed system is currently undergoing an extensive, more than year-long review at the FERC, while New York's system is still being reviewed by the court system to ensure that the FERC did not exceed its authority when approving the New York's new capacity market in 2003.

[10] Weitzman, Martin L., "Prices vs. Quantities," *The Review of Economic Studies*, Vol. XLI (4), No. 128, October 1974, at 477-491.

[11] For example, in Europe, pollution taxes are often favored over standards.

[12] Weitzman, *op. cit.*, at 85.

[13] It may be the case that using demand curves shaped based on consumers' willingness to forego consumption of electricity when facing high prices would be the most appropriate basis for the administrative curves currently in use. At a minimum this would allow thoughtful consideration of the resolution of the price versus quantity control question.

[14] As we mentioned earlier, minimum reliability is defined as the level of installed capacity which ensures a loss-of-load-expectation (LOLE) of 0.1, or one day in ten years, which is the second key input into the LICAP demand curve.

[15] The New England demand curve is that proposed by ISO-NE in its March 1 and August 31, 2004, filings for power year 2005-06. Nevertheless, considerable debate on the appropriate parameters for the curve is ongoing at the FERC.

[16] *United States of America, Before the Federal Energy Regulatory Commission, New York System Independent* [sic] *Operator, Inc., Docket No. ER03-647-000*, Affidavit of Dr. Thomas S. Paynter, at 20.

[17] PER are the "revenues, net of variable costs, that the Benchmark Generator would earn if it were always available." (*United States of America, Before the Federal Energy Regulatory Commission, Devon Power LLC, et al., Docket No. ER03-563-030*, Direct Testimony of Steven E. Stoft, at 20.)

[18] Capacity payments cannot be negative—i.e., if a generator's PERs exceed the LICAP price, no capacity payments are awarded to that generator.

[19] While generators would still be motivated to manipulate spot energy prices by withholding generation capacity, the concomitant reduction in capacity payments would result in market-power abuse having no effect on the overall rents. This may not hold for some low-variable-cost base load generators, whose increases in infra-marginal rents can, in theory, surpass the decreases in capacity payments as a consequence of withholding power. This is a case when infra-marginal rents exceed LICAP price and, since the associated capacity payment, calculated as the difference between LICAP price and infra-marginal rents, is always non-negative, the generator receives zero capacity payment.

[20] *United States of America, Before the Federal Energy Regulatory Commission, Devon Power LLC, et al., Docket No. ER03-563-030, Compliance Filing of ISO-NE, Inc.*, March 1, 2004, transmittal letter, at 5. Although, Southwest Connecticut was added as a zone following a FERC inquiry related to ISO-NE's March 1 filing.

[21] *United States of America, Before the Federal Regulatory Energy Commission, Devon Power LLC, et al., Docket No. ER03-563-030*, Prepared Direct Testimony of James G. Daly on Behalf of the Attorney General of Massachusetts, *et al*., at 42.

(continued on page 28)

Creating a Commercial Environment for Energy Projects –Lessons from Central and Eastern Europe

*By Robert Eric Borgström**

Introduction

Fifteen years ago, "The Wall" came down and its destruction marked both the beginning of an historic period of economic restructuring and an unprecedented commercial opportunity for which many of us were entirely unprepared.

Shortly thereafter, I had left the gas company where I was manager of economic analyses and was in Hungary, as part of a project to evaluate natural gas distribution companies for private sector investment. That fascinating project began the senior third of my career to date, which has focused almost entirely upon the development of a commercial environment for energy projects in the transitional economies, primarily in Central and Eastern Europe but also in Central and Southern Asia.

The objective of this article is to review some of the lessons that were learned through working during this historical period of transition. The points that I shall raise may seem elementary or even self-evident. Nonetheless, I believe that the broad experiences of the past fifteen years should not be assigned to the dustbin of history.

Energy Projects in Transitional Economies

To put things into perspective, when I speak of energy projects, I am speaking of big-ticket projects that will enhance and expand energy supply infrastructures. The IEA's World Energy Outlook for 2002 estimates that meeting the demand for such projects will cost $16-trillion over the first three decades of the twenty-first century. Half of this amount will be spent in developing countries and ten per cent will help to re-create Russia and the transitional economies. This means that there is roughly $50-billion to be raised each year for expenditure in those countries alone. Electricity projects should account for approximately 60% of that total, a requirement of $30-billion annually.

As countries "transit" from controlled to market economies, the public purse will be inadequate to meet the substantial capital requirements for infrastructure projects. Since these funds will need to come largely from the private sector, the State will inevitably be forced by the leverage of the new, private-sector investors to liberalize. This will mean a more efficient restructuring of business units, the hands-on involvement of owner/managers from abroad and the need for current employees to adapt to new paradigms of working or face redundancy.

Lessons Learned

We don't have the only winning paradigm.

Let me speak from the bias of an American, which I am, to say that we tend to believe so strongly in our paradigms for economic success that we fully expect that everyone, if only given access to our methodologies, will happily rush to embrace and adopt them.

However much our commercial success is admired and imitated, the rest of the world does not see its own set of encultured values as being so without merit that their national experience should be tossed into a heap while they listen to the Delphic pronouncements of a visitor from America.

This doesn't mean that we shouldn't clearly explain the parameters of our logic. On the contrary, the great challenge of doing business abroad is to establish a common basis of understanding from which meaningful negotiations can develop. However, the exportation of our commercial philosophy would be more successful if we learned to talk less and listen more; if we were more patient rather than contemptuous of the "inefficiencies" we encounter; and if we were more inclined to recognize that successful cooperation can add strength to a competitive effort.

There are fewer sound investment opportunities than "good ideas" for projects.

The "bottom line" to our business credibility can only be defined by our position on one single filter: will the project make money?

This sounds so elementary that it's hardly worth saying to an audience of energy economists, but in our zeal to pursue a business opportunity, it is sometimes easy to forget that the nature of the transitional economy is to move from doing things because it was politically appropriate to do them, to doing things because investors will benefit from them.

There are many "good ideas" for projects, but very few are worth investing in them. One will encounter no shortage of plans for new generation, the expansion of transmission systems, the betterment of distribution systems and a host of "good" things to drive the national well-being.

In the controlled economy, the merits of a proposal were weighed against socio-political objectives and, if the merits were aligned with the objectives, funds were drawn from the budget for construction. If the economy was a large enough, closed system to be self-sufficient it is possible that the bulk of the construction was without real cost.

Recovering that cost, if any, was rarely a concern since rates for energy from the new asset were typically established by fiat with the objectives of keeping citizens happy and the government in favor. Low cost – or lower-than-cost – energy was frequently a right of citizenship provided by the govern-

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ment in power.

And even if the established tariff did bear some relationship to the cost-of-service – for example, the cost of imported coal or natural gas – realization of those tariffs often reflected the ability of large consumers, state-owned enterprises and municipal systems to exempt themselves from paying their bills.

So I return to my not-so-elementary question of whether or not the project is likely to make money. I can tell you that many times I've asked that question and seen in the faces of my colleagues across the table that the question had never been considered.

Nonetheless, it is elemental that if the government's policy is to provide energy service below cost, the project passes quickly from the interest of the private investor back to the fiscal responsibility of the State. Understanding that investors who raise capital for energy projects have their own social objectives as a priority is an important lesson that many in the transitional economies must learn.

We don't always have the same objective. i.e., the Ministry isn't always on our side.

If numbers like $50-billion are to be raised each year, it is fair to assume that every Minister of Energy is interested in attracting private sector investors. However, potential investors need to know whether the State sees energy as an element of the national patrimony to be husbanded, or does it subscribe to our capitalistic notion that the market is the best guarantor of public interest. Or put another way, it is preferable for the investor to have equity in a project that will respond to signals from its customers rather than phone calls from the Prime Minister.

Today there are energy regulatory agencies in virtually all of the countries of the formerly Communist block in Central and Eastern Europe. This is an important step in moving the control of the energy sector away from political decision-making. In practice, however, many of these regulatory bodies are still in positions of political subservience. It is not unusual for the chief regulatory officer to be removed from office in an overnight political decision amid a flurry of headlines about his health or his alleged corruption.

In very few countries is there the stability that we know in the USA with our tradition of public hearings and elaborately transparent processes of impeachment. This lack of independence should raise red flags for the investor who is evaluating the possibility of equity participation in those states.

The government, through its regulatory agency, should also take leadership in explaining the costs and benefits of private sector investing to its constituents. The new project, whatever form it may take, will cause economic dislocations and public resentments. These results derive from the actions and inactions of the government and its predecessors and the defense of corrective measures cannot become the sole burden of the investor. This must be understood at the outset and be framed within the final negotiations.

The government wonders if we're on their side.

In fairness, just as serious investors should be wary of the Central Authority and its influence affecting operating conditions over the life of the project, State authorities have reason to be wary of the investor. Too many hard lessons were learned during the early days of Mass Privatization:

- large shares of capital given to management to extend their years of control;
- the overnight making of billionaires through the equally expeditious liquidation of enterprises and their assets; and
- the fund scandals that exchanged years of participatory labor for meaningless scraps of paper.

The government official may pause when considering handing-over of the national patrimony to foreign influence under a system of economic exchange that may not be understood.

From a policy perspective, the foreign investment in infrastructure must be constructive and long-term. The investor must demonstrate not only his faith in the prospective project but his wiliness to be patience to await the project's success before expecting a significant return on or of the investment. The impatient have many other more suitable opportunities in which to risk their money.

The project won't help to perpetuate the status quo.

Sadly for some, new business ventures – whether it is a privatization or a significant financial enhancement of the business – will require important changes to the "old" business approach. Utilities around the pre-transitional world tend to be over-staffed and inefficient, it is expected that new projects will bring not only an infusion of useful capital, but also an intervention by new managers, armed with new management philosophies and a focus on international best practices with respect to operations, management and staffing.

These will not be popular changes among existing employees. The inevitable redundancies will require programs for early severance and re-training, which are the fiscal responsibility of the government. It will also require a carefully developed plan to explain that the new changes are inevitabilities, brought-about by the country's economic transition. In this development, the investor should also expect the government's whole-hearted participation.

Indeed, whatever actions are taken in the course of economic reform and restructuring, these actions must take place within the context of a specific public information campaign that will inform stakeholders about the changes to take place and be persuasive about the benefits ultimately to be derived from these measures. The "good news" is that the new energy project will not only provide reliable energy at cost, it will help to fuel the nation's economic recovery and be funded by mechanisms that are fair to all stakeholders. But it will be a hard sell and the investor must have confidence that the participating government will be pro-active in promoting that sale.

(continued on page 28)

About How We Keep Score on Fuel Economy and How it Impacts Greenhouse Gas Production

By David McKeagan*

The methods used to quantify fuel economy need to be questioned. The way we have always done it leads to erroneous conclusions about the relative efficiency of gasoline and diesel engines. It also takes away focus from the importance of fuel chemistry on the relative amounts of greenhouse gases produced in any combustion process.

Fuel economy performance is reported on the basis of liquid volume of fuel consumed (miles/gallon or liters/100 kilometers). The actual power developed in either spark or pressure ignition engines depends on the heat of combustion of the fuel and the stoiciometry of the oxidation reactions. Greater heat of combustion and greater molar expansion give higher cylinder pressure and more power. It is possible to compare fuels using simple gas law calculations. In Table 1, the properties of a few representative fuels are shown. The 'adiabatic temperature' is that which is reached assuming no heat losses and theoretical oxygen requirements. The higher the (cylinder) 'relative pressure', the greater is the power output. The higher the carbon/hydrogen of the fuel, the higher is the relative amount of carbon dioxide (CO_2) produced.

Table 1
Performance Based on Equal Liquid Volume Burned

Fuel	Heating Value BTU/lb[1]	Adiabatic Temperature (^{0}F)	Relative Pressure	Relative CO_2
Octane	19,060	3359	1.00	1.00
Pentane	19,540	3386	0.93	0.89
Toluene	17,640	4002	1.11	1.36
Pentene	19,360	3348	0.95	0.95
Ethanol	11,520	3230	0.69	0.71
Methane	21,540	3270	0.49	0.38
Cetane	18,920	3453	1.13	1.15

This comparison is based on feeding the same liquid volume of fuel into either a gasoline or a diesel engine. Thus, compared to octane (C8H18),[2] pentane (C5H12, a typical light component of motor gasoline) produces about 7% less power. Pentane and octane are fully saturated paraffins and so contain the maximum amount of hydrogen for C5 and C8 carbon molecules respectively. Their relative power output and CO_2 production can be explained by the differences in carbon content and liquid density.

Commercial gasolines also contain olefins and aromatics that are deficient in hydrogen. These compounds come mostly from catalytic cracking. Toluene (C8H10) is an aromatic that produces about 11% more power than octane and is also desirable as an octane number enhancer. Toluene has 'higher energy content,' that is it has a higher density and a higher proportion of carbon than pentane or octane. Thus, it also produces more CO_2 when it burns. Olefins like pentene (C5H10) have intermediate performance between saturated paraffins and aromatics.

Two alternative fuels for gasoline engines are ethanol (C2H6O) and natural gas (methane, CH4). The figures in Table 1 support the view that on a liquid volume basis they produce less power than typical gasoline components, and that they also produce less CO_2.[3]

The traditional basis for comparing diesel fuels uses cetane (C16H34) as a reference. The figures in Table 1 explain why it is observed that diesel engines get 15-20% more miles to the gallon. This advantage is frequently explained by the 'higher energy content' of diesel fuels. However, this observation is purely an artifact of the practice of selling automotive fuels and measuring fuel economy on a unit volume basis (miles/gallon).

Consider how different fuels would stack up if instead the comparisons were done on a weight basis (e.g., miles/pound of fuel or kilograms/100 kilometers).

Table 2
Performance Based on Equal Weight Burned

Fuel	Heating Value BTU/lb[1]	Adiabatic Temperature (^{0}F)	Relative Pressure	Relative CO_2
Octane	19,060	3359	1.00	1.00
Pentane	19,540	3386	1.02	0.99
Toluene	17,640	4002	0.88	1.08
Pentene	19,360	3348	1.02	1.02
Ethanol	11,520	3359	0.60	0.62
Methane	21,540	3270	1.14	0.89
Cetane	18,920	3453	0.99	1.01

The cetane, pentane, pentene, and octane power output is nearly identical, as is the CO_2 produced. This shows that when comparing fuels on an equal weight basis, there is no difference in performance (miles/pound) between gasoline and diesel engines. It also shows that aromatics like toluene only seem to give better performance because of their higher density and higher energy content on a volume basis. Surprisingly, methane outperforms all the other hydrocarbons both on power output and CO_2 production. Ethanol gives the lowest power output; it may produce low CO_2 but per unit of power output, CO_2 generation is not distinguishable from the heavier hydrocarbons.

There is no reason why fuels could not be sold on a weight basis, given the capabilities of modern instrumentation. Fuels sold in bulk outside the United States are marketed this way, as are chemicals and plastics derived from petroleum.

The difference is important when one considers the greenhouse gas producing potential of different fuels. High energy content goes hand in hand with higher density, more carbon in the fuel molecule, and more carbon dioxide produced on burning.

If we measured fuel economy on a weight basis, we would encourage the production of higher hydrogen containing fuels and engines suited to lower molecular weight fuels. Measuring fuel efficiency based on volume encourages the production of 'high energy' fuels and more greenhouse gases. It artificially encourages the use of engines that produce greater pollution.

Footnotes

[1] Lower Heating Value

[2] The thermodynamics of combustion reactions are hardly affected by molecular structure. The kinetics are however dramatically affected by structure, hence the importance of octane and cetane number indexes in actual engine operation.

[3] These comparisons do not take into account the CO_2 given off in the production of these fuels.

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Hydrogen Strategies Under Uncertainty: Risk-Averse Choices for "Hydrogen" Pathway Development

*By Lorna A. Greening**

Abstract: Uncertainty about the future plays a major role in the formulation of policy options. This analysis of the total costs (private and social) with a focus on hydrogen indicates how some of this uncertainty may project into the future. Through incorporating this uncertainty into the decision process, low risk or 'risk-averse' strategies may be identified for choosing a "hydrogen" development pathway.

Introduction

Discussions of energy policy have had a major role in the legislative agenda of the last session of Congress, and may have an even greater role in the upcoming session. Since the early 1970's, many of these discussions along with the resulting energy policies in the U.S. have focused on the introduction of alternative transportation fuels and fuel efficiency policies (Greene, 1990; Kleit, 2004; Sperling, 1988; Sperling and DeLuchi, 1989). Alternative fuels have encountered many barriers to adoption. For example, bio-diesel, one of the closest substitutes for liquid transportation fuels available in terms of the use of existing vehicle technologies, is just now beginning to appear commercially. However, this fuel is on the order of 13 to 22 cents more per gallon when available, does require installation of a separate pump and tank at a re-fueling station, and depending on the blend may cause rubber or other engine components to fail in older vintage vehicles (US DOE, 2001). Therefore, some seemingly minor differences with petroleum based fuels have impeded greater penetration of the fuel. Further, although shown to be quite effective when initiated 1978, fuel efficiency standards promulgated under provisions of the Corporate Average Fuel Economy Standards Act in 1976, have lost much of their effectiveness with time. Without the re-enforcing effects of energy prices, modal shifts and declining load factors have substantially offset improvements in energy efficiency (Greening, 2004).

Most recently, hydrogen powered fuel-cell vehicles have been suggested as another alternative to the U.S. ever expanding demand for petroleum (Dearing, 2000; Sperling and DeLuchi, 1989). These studies, and many similar analyses, have identified a number of barriers to the increased use of hydrogen in transportation applications. In an evaluation of the potential for this use and R&D requirements, these barriers were summarized (NRC and NAE, 2004). As with other alternative fuels, the current operating characteristics of relatively limited driving range, and narrow requirements for ambient temperature for operation of vehicle technologies were identified as a primary barrier. Further, in the hydrogen literature, it has been suggested that even if these characteristics were improved, fuel cells would be no more efficient than a Carnot cycle (Lutz, et al., 2002). However, other researchers have provided evidence that fuel cells could be substantially more efficient than the Carnot (Cooper, 2003; Lawrence Livermore National Laboratory, 2001). Therefore, there is tremendous uncertainty concerning the operating characteristics, and the probable costs of fuel cell technologies even in the short-term.

Environmental considerations also have been been cited as a rationale for the adoption of hydrogen as a transportation fuel. However, various comparative analyses of different means of production have concluded that emissions may merely be shifted from the tail-pipe to the hydrogen production stage for some types of hydrogen production (Wang, 2002). Some methods of hydrogen production may actually increase both emissions and the total energy of the system (Neelis, et al., 2004). Although, the least expensive means of hydrogen production at the moment is natural gas reformation, greenhouse gases (GHG) are still emitted, and domestic natural gas resources are declining. The EIA forecasts approximately 15% of our natural gas consumption in 2025 will be supplied by imported LNG, most of which is expected to originate in the Middle East (EIA, 2004). Therefore, increased use of hydrogen, depending upon the means of production, may not provide the promised environmental benefits, nor lessen U.S. dependence on foreign sources of fossil fuels. These benefits maximize only when hydrogen is produced using renewable or nuclear sources, however, there are trade-offs associated with the use of those commodities particularly in the case of nuclear energy (Greening and Schneider, 2003).

Perhaps the biggest barrier to the penetration of hydrogen, which has often been cited as the overwhelming barrier, is the infrastructure requirements for hydrogen distribution. Distribution of hydrogen for transportation use is particularly difficult, owing to the need to use very high pressures or very low temperatures which greatly adds to the difficulty in storage and distribution. If a hydrogen supply chain that parallels the existing supply chain for gasoline is constructed, it has been estimated that between 4500 and 17,700 stations would be required to initiate the system with a capital investment of between \$7 and \$25 billion (Melaina, 2003). If the traditional supply chain is abandoned in favor of distributed hydrogen production and distribution, carbon sequestration becomes more difficult, and many of the environmental benefits from hydrogen are substantially reduced. Also, it should be noted that with a greater dependence on a gaseous fuel, either natural gas in the case of production or the distribution of gaseous hydrogen from central production, the fuel transportation system becomes more vulnerable to protracted disruption (Corbet, 2004). The existing liquid fuel system responds much more slowly and recovers more quickly than a gaseous based system.

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*Lorna A. Greening is an Energy, Consultant based in Los Alamos, NM. She can be reached at lgdoone@aol.com I wish to thank my many colleagues at Sandia National Laboratories, especially Glenn Kuswa and Thomas F. Corbett, for their thoughtful and helpful comments during the preparation of this article. I take full responsibility for all errors of omission and commission, and any opinions presented are solely mine and do not represent the views of any other organization.

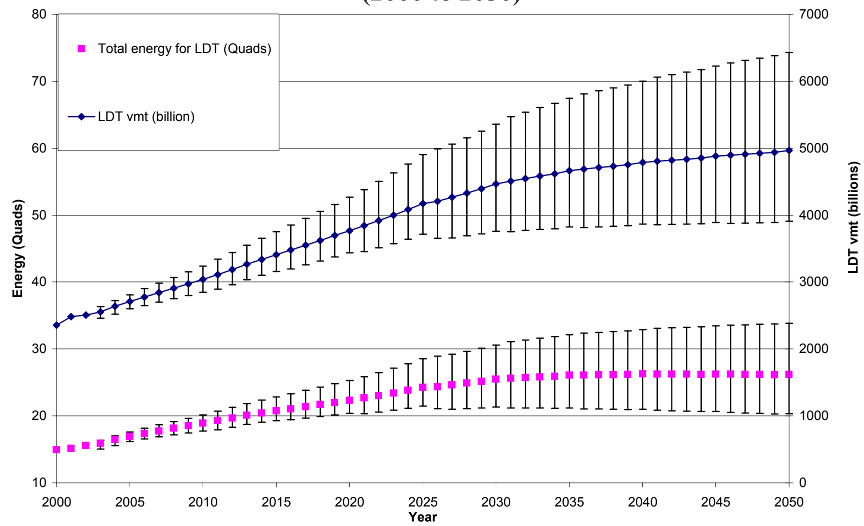
Energy and environmental policies have a number of characteristics in common, but are also dissimilar in a number of respects (Greening and Bernow, 2004). Both types of policies embody uncertainties evolving from long time frames, and capital-intensive investments (Huang, et al., 1995). However, the uncertainties associated with each stem from different sources. But, with the recognition of the nexus between energy consumption and production and the possible degradation of environmental amenities, developing coordinated approaches to energy and environmental issues has become a primary goal for the policy formulation process. The discussion presented here begins to examine how uncertainties about characteristics of potential energy policy options when combined and compared can lead to less risky or 'risk-averse' choices. Several different criteria in addition to private costs have been included in this analysis. To do this, the 'controversial' step of monetizing some of the externalities has been used. However, it should be noted that there are other well accepted means of including externalities in the decision process, and those methods are being used in further research.

Many of the previous analyses of both the life-cycle costs and emissions have used a static approach (e.g., Ogden, et al., 2003) where fuel prices and the technological characteristics of vehicles and fuel production are assumed constant. Further, these previous analyses have not explicitly recognized the uncertainties associated with the valuation of externalities (i.e., social costs). In the work presented here, uncertainty concerning the potential prices of fuels, and technological characteristics has been explicitly recognized. In addition to market cost uncertainties, an attempt has been made to quantify other attributes, such as emissions of GHG and potential levels of imports of fossil-fuels, and provide an economic valuation. By the incorporation of other attributes in the analysis process, we begin to provide an understanding of some of the trade-offs that might be necessary in selecting one technology over another for support. As a result, policy- or decision-makers can broaden their basis for decision from just the private cost attributes.

Uncertainty and Hydrogen Choices

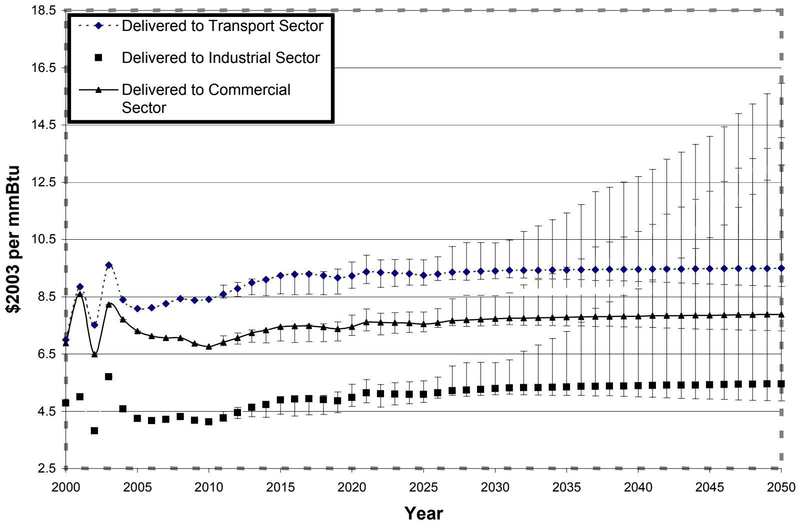
In order to evaluate many of the uncertainties associated with the potential development of our future transportation system, personal vehicle miles traveled (vmt), energy consumption for personal transportation, vehicle and hydrogen production technology costs, and costs for various fuel commodities were forecast out through 2050. These forecasts were developed with three cases from the Annual Energy Outlook 2004 (reference, and high and low economic growth) and long-term population forecasts from two sources (Bureau of the Census, 1996; O'Neill, et al., 2001; United Nations Population Division, 2003). As demonstrated by Figure 1 of a forecast for vmt and total energy for light duty travel, this approach illustrates the uncertainty in projecting future transportation energy needs and costs, and the impacts of the penetration of alternative transportation fuels and technologies into the future. Personal vehicle miles traveled could reach levels of between approximately 3500 and 6100 billion by 2050. Similarly, total energy consumption for this mode of transportation could reach levels of between 18 and 32 quads with an expected (or reference level) of slightly over 26 quads by 2050. These levels translate into average annual growth rates of 0.4% to 2.3% and reflect the effects of expected improvements in fuel efficiency during the forecast period.

Figure 1
Forecasted Light Duty Personal Vehicle Miles Traveled and Energy (2000 to 2050)



To illustrate further the uncertainties in the analysis of the future costs of transportation alternatives, forecasts of future energy prices were prepared and incorporated into this analysis. Figure 2 provides an example of the uncertainty of prices for natural gas delivered to the transportation, commercial, and industrial sectors. This uncertainty could impact the private costs of travel to one extent or another for several different fuels including compressed natural gas and hydrogen produced from both distributed and central steam reformation. The reference case prices for natural gas assume that although domestic production of natural gas has flattened, imported supplies of LNG are readily available through 2050. The error bounds on those prices, however, begin to capture the potential effects of world competition for LNG from the developing portions of the world, the possibility that our resource estimates for recovered resources in North America are less than currently anticipated, and the over-all depletion of fossil-resources. As a result, natural gas prices could reach levels as high as 250% over forecasted reference levels in 2050, and reflect the possibility of short-falls in supply. These potential levels of price, however, do not consider the potential for fuel substitution nor acceleration of technological improvements. This same type of analysis was also performed for other fossil-fuel commodities such as the

Figure 2
Forecasted Delivered Price of Natural Gas



delivered price of coal, distillate, gasoline, and other market-based commodities.

To illustrate how these future uncertainties might impact the costs per vmt of different vehicle alternatives, Monte Carlo simulation was used to perturb the components of total costs (private and some social) of personal travel (vmt). This approach allows for a better understanding of the cumulative uncertainty in a system than might be derived from the use of individual scenarios. This analysis, also serves as the first step in development of a multi-criteria decision support framework incorporating uncertainty and additional attributes. As discussed in the following, this particular analysis includes only a very small sub-set of potential externalities from personal transportation. The inclusion of additional categories may amplify or reverse the conclusions made here. Therefore, this is an area of on-going research.

Vehicle costs and costs for production of hydrogen, and energy usage were derived from various sources. Vehicle costs and energy usage were obtained from the OTT/DOE, and are consistent with such other sources such as the AEO (EIA, 2001, 2004; Office of Transportation Technologies, 2002). Future vehicle costs and efficiency trends were projected using trends established in the Annual Energy Outlook. Costs for a selected number of hydrogen production, transportation, and delivery technologies were taken from several sources and compared with the NRC study (Amos, 1998, 2004; NRC and NAE, 2004; Simbeck and Chang, 2002). Other modeling efforts have included a greater number of production technologies (Greening and Schneider, 2004), however, for this illustration of the effects of uncertainty only a number over this range were examined.

Both vehicle technology costs and fuel efficiencies are assumed to have different rates of potential technological change depending upon the current development of a technology. Fuel price uncertainty is treated through projection of a spread of prices for each fuel commodity over the forecast horizon extending from 2000 to 2050. To incorporate some of the impacts of unpriced externalities, estimates of the potential damages from GHG and the increased or forecasted increased dependence upon imported sources of fossil fuels such as petroleum and petroleum products, and natural gas were also estimated. These two externalities have been argued by some to be particularly important for personal transportation in the U.S. (Greene, et al., 1997); however, others have argued that criteria pollutants and congestion produce greater welfare losses. As a result of this approach, we can identify technologies which may over the course of time in the face of uncertainties from a number of different sources offer lower total private and social costs on a per vmt basis. This then allows us to suggest areas of emphasis for research and development of alternative fuels, particularly hydrogen.

Emissions damages estimates were calculated for only greenhouse gases (i.e., CO_2, CH_4, N_2O, VOCs, NO_x, and CO). Different weighting schemes can be used to combine these species into a CO_2-equivalent measure. But, for this analysis, a scheme where distributions have been developed for each of the weights was used (Contadini, 2002). This captures the uncertainties associated with the climate forcing capacity of each gas (IPCC, 1996). To further incorporate these uncertainties, we have used a range of values for our proxy cost of environmental damage from GHG emissions. Following Ogden, et al (2003), a cost of carbon dioxide ranging from approximately \$18 to not quite \$50 per tonne of CO_2 was assigned to the CO_2-equivalent emission. This range of costs represents a 95% confidence of potential damages, and is consistent with estimated costs of achieving maximum levels of capture and sequestration. Finally, the full-fuel cycle estimates developed in GREET 1.6 were used (Wang, 2001). As a result, damages were estimated for "well-to-wheel," and thus consider all vehicle/fuel combinations on a comparable per vmt basis.

Security costs were estimated once again in a manner consistent with Ogden, et al. (2003). These authors used an estimate of between \$20 and \$60 billion per year to safe guard access to Persian Gulf oil. However, considering recent experience (i.e., Iraq and Afghanistan), and whether we ascribe all Middle East military costs to oil, this range may be low. Ogden, et al., use a range of between \$0.35 to \$1.05 per gallon of gasoline equivalent with a likely value of \$0.70 estimated on the basis that 20% of U.S. oil imports originated in the Persian Gulf in 1999. Since oil is fungible with an established commodity market, any disruption would be felt in across-the-board price increases. Therefore, this risk premium was assigned to the imported share of petroleum without regard to point of origin. Further, the share of imports was forecasted out through 2050, and as a result, the oil security component of total price will increase with time for petroleum-fueled vehicles. Since imports of LNG are also expected to increase in time, they will probably be substantially from the Persian Gulf area, and will provide an increasing component of our natural gas supply, the security premium was also applied to imported LNG. As a result, this premium on a per vmt basis increases for natural gas based vehicle options (e.g., CNG dedicated, hydrogen produced from central or distributed natural gas reforming) over the forecast horizon. If other sources of energy, such as nuclear, were used in the generation of hydrogen, other issues surrounding supply security and environmental considerations would need to be included in the analysis (Greening and Schneider, 2003). However, for this analysis, those potential sources of transportation energy have been excluded.

To illustrate the relative differences between various personal vehicle technologies, Figures 3 and 4 show total costs of each of the technologies for three points in time, 2005, when all of the technologies are assumed to be fully commercialized and available to the consumer, 2025, and 2050. Error bars on the total costs for each technology reflect the uncertainties from a number of sources that have been aggregated into these estimates. Figure 3 focuses on fuel cell technologies, and reflects both private and the externality costs included in this analysis. All of these fuel cell technologies use hydrogen with the exception of reformulated gas fuel cells and internal combustion engines, both using reformulated gasoline, and the hydrogen-fuel cell technologies have the same initial investment costs and same development (i.e., technological change) trajectory. Therefore differences in total costs arise from fuel production costs, and the estimated values for emissions damages and security costs.

Figure 4 provides an overview of total costs for other vehicle options that would be considered as competitors to fuel cells. Once again the costs for an internal combustion engine using reformulated gasoline are provided as a yardstick. And, as with Figure 3, error bars on the estimates provide an indication of the potential uncertainty of the total cost estimates.

Figure 4
Other Potential Personal Transportation Options

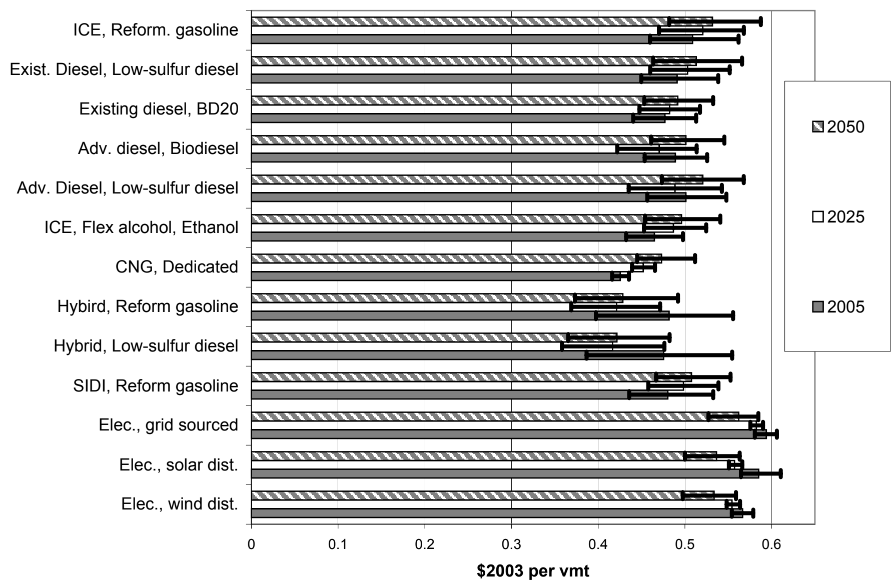
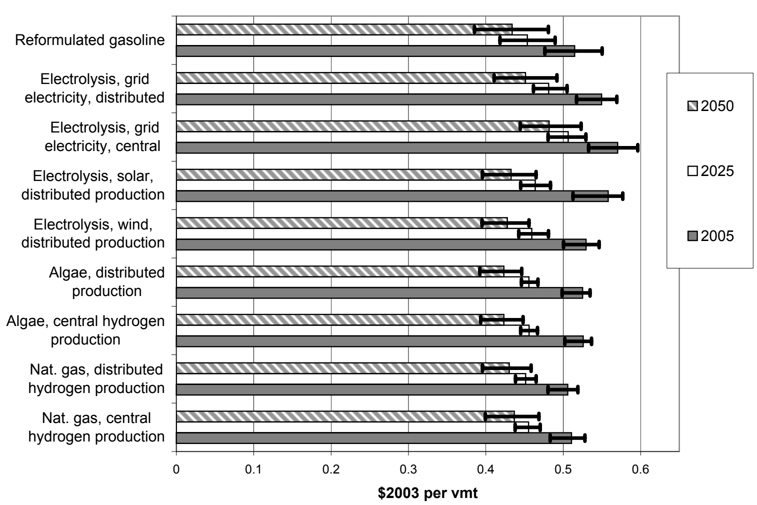


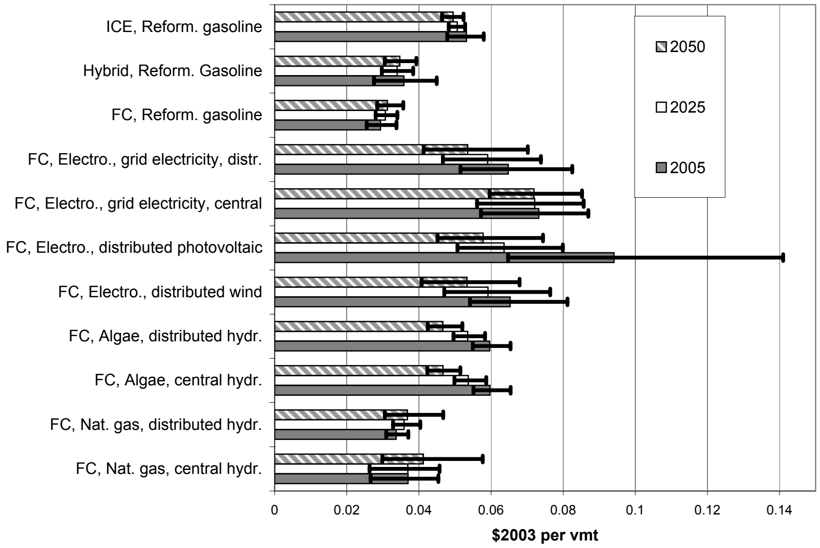
Figure 3
Total Costs for FC Technologies in Comparison to Reformulated Gasoline ICE



In general as would be expected, gasoline and diesel technologies (existing, hybrid, and advanced diesel) offer a cost advantage on a per vmt basis in 2005. However, as levels of imports increase and uncertainty increases concerning potential prices of petroleum-based fuels, this advantage begins to erode. Even with anticipated increases in fuel efficiency, the potential parallel decreases in costs and improvements in operating efficiencies of renewable-based technologies along with the absence or low levels of emissions damages and security costs begin to assume an advantage. For distributed generation sources of hydrogen, renewable-based sources exhibit substantial declines in cost. These technologies have no or minimal security costs or GHG emissions damages associated with them, thus fewer sources of uncertainty. And, for some of these technologies, during the period 2005 to 2025, actually achieve lower total costs per vmt than petroleum-based options.

Figure 5 provides estimates of the range of fuel costs per vmt for the suite of fuel cell options, along with a hybrid, and an internal combustion engine, both using reformulated gasoline. Error bars once again illustrate the potential uncertainty of these costs either from projected market uncertainty or from production costs (e.g., hydrogen), and the vehicle technology fuel efficiency. All vehicles are assumed to be full-size, although this same evaluation can be performed for other vehicle sizes. Due to the relative uncertainties associated with the technological development of automotive fuel cells (both hydrogen and gasoline), the operating efficiencies of these technologies have been kept constant over the forecast horizon; however, initial costs were projected to decline. Efficiencies for the ICE and hybrid technologies improve slightly over the forecast horizon. All operating efficiencies are varied using a triangular distribution providing for a lower, expected, and upper value; this is an area of further research, and refinement of these assumptions is in progress. Hydrogen production costs with the

Figure 5
Fuel Costs for Selected Technologies



exception of the fuel inputs (e.g., electricity and natural gas) are held constant over the time horizon; however, those costs are perturbed over a range during each time increment. Holding costs constant does ignore the effects of technological change which has played a role in reducing costs for other technologies, and hydrogen production is assumed to be no different. Examination of Figure 5 indicates that fossil-fuel based technologies have the lowest cost per vmt for fuel with the least uncertainty even with the large potential spreads in projected fuel costs. Costs for fuels generated from renewables have the greatest uncertainty, but also the greatest decreases over the forecast horizon.

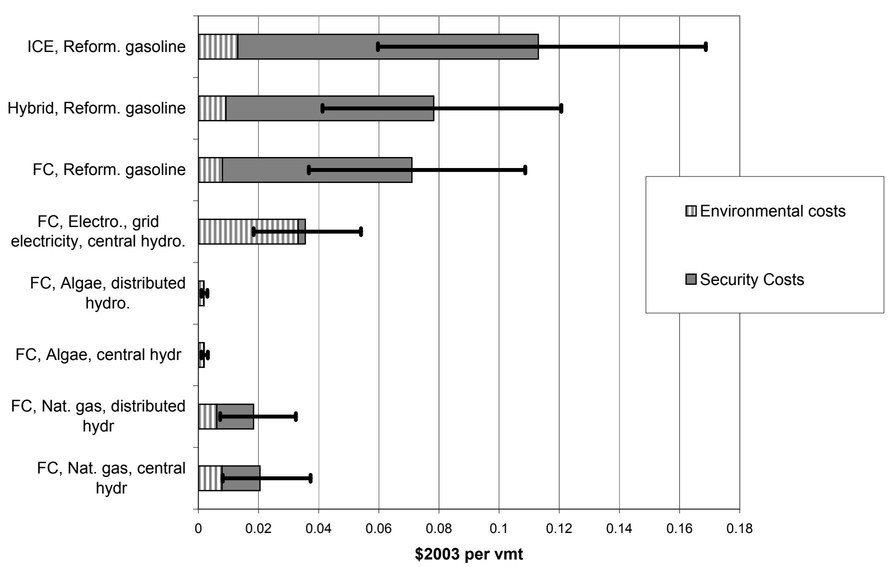
Figure 6 illustrates the potential contribution of environmental damages and security costs to total costs of selected technologies in 2050. Although fuel efficiency is improving for fossil fueled vehicles, those declines are off-set by an increase in the shares of imports expected in our fuel mix. Should shares of imports increase radically above expected levels due to say an incremental demand in natural gas or domestic resources are less than currently anticipated, then this portion of the costs per vmt will increase above these expected levels. Differences in environmental damages between renewable- and fossil-based technologies are readily seen. In the cases of distributed hydrogen production using wind and solar, no environmental or security costs are incurred. Environmental damages are greater for central production due to losses of between 5 to 10% during transmission, and between 4 and 5% from the dispensing of fuel. As a result, approximately 10 to 15% more hydrogen must be produced from central generation in order to provide one unit to the end-user. Depending upon the source of energy used, emissions damages may actually be on par or greater than more conventional petroleum-based vehicle types.

Conclusions, Policy Recommendations, and Comments on Further Work

Given the results of this initial evaluation with uncertainty for various transportation options, the following set of preliminary conclusions seems appropriate:

- If the full costs (private and social) of a vehicle mile were included in the cost per vmt, fuel cell vehicle technologies for some sources of hydrogen are probably competitive with more traditional petroleum-based technologies within the next 10 to 15 years. However, there is a high degree of uncertainty from the initial costs of a fuel-cell vehicle, operating efficiency, and fuel source.
- Uncertainties concerning transportation fuel prices and supplies may very well off-set fuel efficiency gains for petroleum- and natural-gas fueled options. Particularly, as we look further out to the future, previous polices aimed at fuel efficiency may no longer be sufficient to reduce or moderate aggregate demand for these fuels.
- Distributed sources of hydrogen provide a cost and energy advantage through avoiding the potentially costly transmission process with the accompanying energy losses. In other words, during the initial stages of development of the hydrogen economy we will probably jump out of the traditional supply chain. Further, security costs and environmental damage costs are smaller in comparison to fossil energy-based hydrogen generation sources.
- Although carbon sequestration is an option with centrally produced hydrogen, even in 2050, GHG emissions damages constitute only a small proportion of total costs for centrally generated hydrogen from algae (0.43%), natural gas (1.40%) and grid-sourced electricity (6.89%).

Figure 6
Environmental and Security Costs for Selected Technologies in 2050



Therefore, more analysis needs to be done on the trade-offs between carbon sequestration for carbon from hydrogen generated using fossil fuels against the use of local sources of renewables for generation. The additional energy consumption from central generation of hydrogen may far outweigh the benefits.

- Alternative fuels are not all equal. Fuels such as ethanol and bio-diesel shift environmental burdens from the tail-pipe to the "front-end" and can result in higher emissions of methane, a gas with a greater climate forcing capacity. Similarly, the increased use of natural gas either in compressed form or as a feedstock for hydrogen may very well lead to increased dependence on foreign sources, and may only lead to a partial environmental benefit.
- In making choices concerning future transportation options or any energy use for that matter, inclusion of externalities either through valuation or direct physical quantities is a crucial part of the analysis. Without inclusion of these attributes, decisions may be made on an erroneous basis.

For hydrogen development strategies, several insights can be drawn:

- Local sources of renewable energy (wind, solar, and biomass) provide the maximal environmental, energy, and security benefits; and, probably more so then natural gas, may lead to the initiation of the 'hydrogen' economy. As a result, a major emphasis needs to be placed on hydrogen conversion techniques for these resources. The hydrogen R&D program announced by U.S. DOE in October reflects this observation.
- Given the currently large initial costs, the uncertainty on how those costs might decline, the operating characteristics of fuel-cell vehicles and other issues surrounding the use of hydrogen, initial costs for vehicles would need to decline to levels currently found with hybrids for market penetration into fleet markets. Cost declines can be achieved to some extent through R&D. However, drawing on previous experience with alternative fuels, demonstration projects and tax subsidies will undoubtedly be required for wider spread penetration.

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Ensuring the Future Construction of Electricity Generation Plants *(continued from page 18)*

[22] The estimates of the cost of new gas-fired combustion turbines for New York City, Long Island, and upstate New York are \$159, \$139, and \$85 per kW-year (Paynter, ER03-647-000, *op. cit.*, at 22); in New England, the same cost estimates for NEMA/Boston, SWCT, Rest-of-Connecticut, Maine, and Rest-of-Pool are \$97.87, \$99.16, \$96.52, \$87.22, and \$92.34 per kW-year, respectively (*United States of America, Before the Federal Regulatory Energy Commission, Devon Power LLC, et al., Docket No. ER03-563-030*, Direct Testimony of David LaPlante, at 16).

[23] New York's electricity consumption is more prone to spikes, which is a reflection of greater population concentrations.

[24] 1.12 times 1.038 is approximately 1.16.

[25] In New England, the level of installed capacity at which price falls to zero is not a parameter in itself, but is instead mathematically determined by the other parameters. (Stoft, *op. cit.*, at 81.)

[26] New York: 1.18 times 1.12 is approximately 1.32; New England: 1.12 times 1.15 is approximately 1.29.

[27] Stoft, *op. cit.*, at 81.

[28] The "target" level of installed capacity in New England is 5.4% above objective capability.

[29] Stoft, *op. cit.*, at 48.

[30] NYISO estimates the expected net revenues that a new combustion turbine would earn, per, year, by selling into the energy and ancillary services' markets based on the assumption that the electric system is at its minimum capacity requirement. (Paynter, *op. cit.*, at 20.)

Creating a Commercial Environment for Energy Projects *(continued from page 20)*

Conclusion

Each of these "lessons" – and there are, of course, many others - can define a project as having positive economic impacts upon its stakeholders, or signal that the prospective investor should move on to other opportunities.

I am optimistic that the reach of global investment will continue to penetrate the barriers that older generations of managers, politicians and investors have created from their own innate conservatism and arrogance. New generations arising in the transitional economies will not have the restrictive baggage of controlling state environments and will be more nimble, creative and constructive in working with the foreign investors.

I am optimistic, too, that from our side of the world, our own investors, negotiators and entrepreneurs will be more global with their vision and constructive with the energy investment opportunities that the future will present.

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Energy is forefront in the news again! Will coming years take us to clean, cheap, stable, and secure energy supplies with ever-increasing prosperity? Concentrated plenary sessions combined with diverse concurrent sessions and ample networking opportunities will provide the backdrop for exploring a wide-range of issues within energy markets while enjoying a view of the Rocky Mountains in a congenial atmosphere.

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Fossil Fuels Reliance & Reserves
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Electricity Reliability: Boom to Bust & Back Again
Oil & Natural Gas Market Volatility
Renewable Energy: Back to the Future?
Energy: International Commodities
Non-Conventional Energies: Probable to Proven

Possible Concurrent Session Topics

Concurrent sessions will be developed from the papers selected for the program. Among the possible topics are: Electricity markets; geopolitics of energy; international energy markets; global LNG; Kyoto Protocol revisited & emissions trading policies; transport sector challenges; forecasting, modelling & scenario developments; energy efficiency & renewables; avoiding bottlenecks & blackouts; nuclear power revisited; sustainable development; private vs. public ownership & use; energy supply & demand; energy policy discontinuities and the climate change debate.

All topic ideas are welcome and anyone interested in organizing a session should propose the topic and possible speakers to:
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The 6th European Conference on **"Modelling in Energy Economics and Policy"** was held from September 1st to 3rd in Zurich, Switzerland. Organizers of this recent international conference were the Swiss Association for Energy Economics (SAEE) and the Centre for Energy Policy and Economics (CEPE) of the Swiss Federal Institute of Technology (ETH). The SAEE, directed by Prof. M. Filippini, was founded in 1984 as the Swiss chapter of the IAEE and is, with 124 members, one of the 16 largest affiliates of IAEE (3200 members).

More than 200 persons (coming from 20 nations) from academia, industry and government attended this conference with a wide variety of interesting presentations. The conference started with the welcome reception at ETH, where the mayor of Zurich, Elmar Ledergerber, emphasized the importance of energy politics and economics in the context of urban sustainability policies.

The organizers could convince a group of distinguished world-class researchers to engage as keynote speakers: Derek Bunn (London Business School, UK) opened the first plenary session with a speech on strategic behaviour in electricity markets, one of the key topics of the conference. Lester Hunt (University of Surrey, UK) gave an instructive overview on the econometric modelling of demand functions. The second session started with two outstanding exponents: Michael A. Crew (Rutgers University, USA) with a talk on recent trends in regulatory economics, followed by William Greene's (New York University, USA) presentation on statistical analysis of cost inefficiency. The last plenary session dealt with another important topic of the conference: Christoph Böhringer (ZEW, Germany) covered with his presentation the top-down general equilibrium modelling, followed by Mark Jaccard (Simon Fraser University, Canada) on energy-economy models for simulating policies. Finally, William W. Hogan (Harvard University, USA) had his speech on electricity market modelling.

As in the keynote talks, a variety of topics were covered in the parallel sessions. In addition to the ones already mentioned there were topics such as environmental economics, gas market modelling or diffusion of technological change. In total, there were 25 parallel sessions (plus one special meeting on energy models for developing countries). Organizing three speeches in a 90 minute session turned out to be a productive framework for a stimulating discussion of many theoretical and applied papers.

The feedback the conference collaborators collected from the different participants was enjoyably positive. Not only the professional aspects of the conference, but also the social events were quite successful. The gala dinner on Uetliberg ("Top of Zurich") was held in a very nice weather and was accompanied by a folkloric show (see picture near by).

After the conference, the participants were offered the possibility to attend two different excursions: an excursion to Eglisau at the Rhine with a visit of one of the oldest hydro-

power plants in Switzerland, and a trip to Ticino (in the south of Switzerland) with a hike and a typical meal in an alpine hut. As can be seen from the picture above, also this day was blessed with sunshine and a good end of a few fruitful working days.

Useful links:

- Swiss Association for Energy Economics (SAEE), www.saee.ch
- Centre for Energy Policy and Economics (CEPE), www.cepe.ch
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(continued on page 33)

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