IA INTERNATIONAL ASSOCIATION FOR ENERGY ECONOMICS
EE

Newsletter

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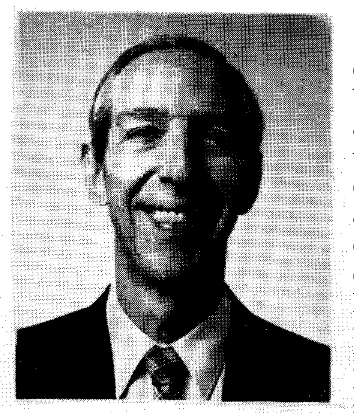
Third Quarter 2002

President's Message



Our 25th International Conference in Aberdeen was a great success. We had excellent attendance, a strong program, and thoroughly enjoyable social events. More than 300 attendees participated in the conference. We had many excellent plenary sessions, led off by a session on a "New Global Energy Policy," with three strong presentations by U.S. Department of Energy Assistant Secretary Vicky Bailey, International Energy Association Executive Director Robert Priddle, and World Energy Council Secretary-General Gerald Doucet. With the Conference taking place in the heart of the North Sea oil and gas area, our second plenary focused on the North Sea in a Global Context, with representatives from BP, the UK Government and Norway's Petoro (the new entity that administers the Norwegian State Direct Financial Interest). At our lunch on the first day, Lord Nigel Lawson, a former Chancellor of the Exchequer and Energy Minister, provided the Conference with a strong retrospective on the United Kingdom's experience in privatization in the electricity sector. Mistakes made, yes, but overall, the privatization effort went exceedingly well! In the afternoon of the first day we divided into co-plenary sessions with one session focusing on Middle East issues and the other on U.S. Regulation, both outstanding sessions, making it difficult to choose which to attend. On the second day, we led off again with two co-plenary sessions, the first focusing on the UK experience in liberalizing electricity markets, an excellent detailed discussion following on Lord Lawson's previous presentation, and the second focusing on de-regulation and liberalization in developing countries. Later on the second morning we enjoyed two more co-plenary sessions, with one focusing on Asian issues and the other on European Issues. Our luncheon speaker on the second day was Mike Lynch on the Perils of Forecasting – be forewarned, your forecasts are fodder for Mike's next presentation! We concluded our conference on Saturday with presentations by Shell and BP on their view of the future (not a forecast) and then a retrospective by eight past presidents commenting on a range of issues important to energy and the IAEE. Of course there were 21 concurrent sessions, and many poster sessions to fill out a very strong program.

The conference was not all about work. There were ample opportunities for networking, catching up with old friends, making new friends, and exploring opportunities for new collaboration. We held an opening reception at the University of Aberdeen in a hall that dates back several centuries. We held a gala dinner at Ardoe House, a beautiful baronial mansion on the outskirts of Aberdeen. We were entertained by a local Piper band (from Alex Kemp's village) that first played out in the rain and then indoors. The head table was "piped" in by a lone piper, who was given his due reward of a glass of single malt scotch and then the entire assembly was toasted by the piper in Gaelic. The City of Aberdeen put on a grand evening of traditional Scottish food and entertainment. We were warmly welcomed by Lord Provost (equivalent to our Mayor) Margaret Smith, and treated to an evening of music, highland dancing, piper, award winning fiddler, and singers.

The conference and related festivities were all made possible by the extremely hard work of the British Institute for Energy Economics and especially through the work of

(continued on page 2)

Editor's Notes

This issue includes the paper by Barry Posner, winner of the 2002 Best Student Paper contest. Posner notes that some feel the U.S. clean gasoline laws have created "fuel islands", disjointed markets which have higher prices than the old, unfragmented market. Many assumed this to be the cause of the gasoline price shocks of 2000 and 2001. He examines the relationship between price shocks and "fuel island" size and finds no significant correlation.

Mamdouh Salameh describes the potential of the Caspian Basin, noting that it is destined to play a supporting role rather than a deciding one is future world oil supply, and that the price of oil will be crucial in determining the development of the Caspian and it contribution to world oil supplies.

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President's Message *(continued from page 1)*
Paul Tempest and Neil Atkinson, who co-chaired the program committee, and Alex Kemp, the Conference Chair. On behalf of the IAEE, I extend a very warm and heart-felt thank you to Paul, Neil, Alex, Fiona (Alex's assistant), and all the others who made the conference such a great success. Of course, we cannot overlook AMS, our management company, and Dave Williams, Sr. and Dave Williams, Jr. for their excellent efforts in supporting us leading up to and through the Conference. We look forward now to the North American Conference in Vancouver, British Columbia, Canada on October 6-9, 2002, and to our next IAEE Conference in Prague, Czech Republic, on June 5-7, 2003.

We also held a Council meeting and strategy session on the day before the Conference started. We held the strategy session in order to provide time for a relaxed discussion about the future direction of the organization now that it has been around for 25 years. We are a financially strong, stable organization; however, we cannot sit on our laurels. We want to reach out to new members and areas of the world where we are not strong. We discussed how to move forward in our outreach, agreeing to focus on a few countries or regions at a time. Our Vice President for Development, Peter Fusaro will be putting together ideas in this regard. We have had a strong student program and we agreed that we want to continue our outreach to students – our future membership and leadership. We have two graduate students, Monika Mechurova and Peter Kobos, who sit on our Council, and their advice has been critical to the success of our student outreach and involvement. We plan to continue this outreach for the future. We have two publications, the Energy Journal and the Newsletter. We agreed that the Energy Journal will continue as it is, a respected, refereed publication. However, we also agreed to take a hard look at our Newsletter and asked Paul Horsnell, our Vice President for Publications, to come up with ideas about how we could transform this publication into a special "policy" publication with timely, lively, articles. We will hear from Paul at our October meeting in Vancouver. We will continue with the development of our website, and have agreed to employ a full-time webmaster to maintain it and upgrade it to meet the needs of our membership. Finally, we agreed to take a hard look at our budget for the next several years to make sure that we remain financially sound as we expand our efforts to reach out to more members, attract students, and continue to serve the needs of our existing members.

All in all, we had a very busy, productive and enjoyable stay in Aberdeen, despite what the Scots call "summer" – gray, overcast, rainy, windy, chilly, and this is on a good day. For those who stayed on to enjoy the countryside, castles, grand houses, distilleries, and general good cheer of the people, there was universal praise for the overwhelming Scottish hospitality. It was a grand time, enjoyed by all!!

Len Coburn

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

Jonathan Skolnik and Chris Holleyman examine oil and gas production in the offshore Alaskan Arctic and note that this requires a unique set of technologies. Economic impact modeling of these activities also requires unique methods. They describe the development of a model that, combined with an available regional model, is designed to produce more accurate estimates of economic impacts.

Fereidoon Sioshansi reports that over a decade has passed since electricity market liberalization process started in England and Wales. Since then much has been learned about what works, and what doesn't, but many complicated issues still remain unresolved. Policymakers who once believed that market liberalization would cure all ills now realize that the process is more complicated than first assumed; that things can – and occasionally *do* – go wrong. And when they do, they can have serious consequences.

IAEE Seeks Affiliate Bid for 2006 Conference

IAEE Council is actively seeking Affiliate bids to host the 2006 International Conference. Experience has shown that our meetings take long lead times to plan and implement successfully. The host Affiliate should keep a few points in mind.

Program

Development of a solid program incorporating a balance of industry, government and academia is critical to the meeting. A general conference chair and program co-chairs should be selected that have excellent contacts within the field of energy economics.

Sponsorship

Successful sponsorship for the meeting is a minimum of $60,000. $75,000 - $100,000 targets, however, should be set.

Logistics

A suitable convention hotel should be secured as well as social and technical tours arranged.

If you are interested in submitting a bid to host the 2006 IAEE International Conference please contact either Peter Fusaro, IAEE's Vice President for Conferences, at (p) 212-333-4979 / (e) peterfusaro@global-change.com or David Williams, IAEE Executive Director at (p) 216-464-5365 / (e) iaee@iaee.org

For a complete conference manual further outlining the IAEE International Conference and the various planning aspects of the meeting please visit our website at www.iaee.org/en/conferences/

IAEE Nominations for 2002 Elections

The 2002 IAEE Nominations committee is pleased to present the following nominations. Each candidate has accepted the nomination and is aware that this is a contested election. They have each agreed to allocate the necessary time to the post and to attend two Council Meetings each year.

President Elect

Tony Owen - University of New South Wales, Australia
Alex Kemp - University of Aberdeen, Scotland, UK

Vice President for Development and International Affairs

Carlo Andrea Bollino - University of Perugia, Rome, Italy
Jan Myslivec - CityPlan, Prague, Czech Republic

Vice President and Treasurer

Wumi Iledare - Louisiana State University, USA
Andre Plourde - University of Alberta, Canada

The Nominations Committee for 2002 comprised of Peter Davies, Tony Finizza, Hoesung Lee, Paul Tempest and Campbell Watkins.

!!! MARK YOUR CALENDARS — PLAN TO ATTEND !!!

Energy Markets in Turmoil: Making Sense Of It All

22nd USAEE/IAEE Annual North American Conference – October 6-8, 2002
Vancouver, British Columbia, Canada – Sheraton Wall Centre Hotel

We are pleased to announce the 22nd Annual North American Conference of the USAEE/IAEE, ***Energy Markets in Turmoil: Making Sense Of It All,*** scheduled for October 6-8, 2002, in Vancouver, British Columbia at the Sheraton Wall Centre Hotel.

Please mark your calendar for this crucial conference. Some of the key selected themes and sessions for the conference are listed below. The plenary sessions will be interspersed with 24 concurrent sessions designed to focus attention on major sub-themes. Ample time has been reserved for more in-depth discussion of the pa pers and their implications. Plenary Sessions include:

Energy Security in the 21st Century
Session Chair: Robert Ebel
- Geopolitical Risks
- Growing Asian Import Dependence
- Reliable Suppliers – Russia, Central Asia, the Caspian

Continental Energy Markets Prospects
Session Chair: Leonard Coburn, U.S. Department of Energy
- Enhanced Regional Integration
- Common Energy Picture
- Harmonization on Standards

California Fallout: What Useful Lessons Can Be Learned?
Session Chair: Perry Sioshansi, Henwood Energy Services, Inc.
- What Went Wrong?
- Resolving the Situation
- Lessons for Other Jurisdictions

Offshore Petroleum Industry: Reflections on Moving Forward
Session Chair: Merete Heggelund, Norsk Hydro
- Economics of Offshore Projects
- Local Procurement for a Global Industry
- Environmental Issues

Canada – U.S. Natural Gas Trade Prospects
Session Chair: Campbell Watkins
- Resource Prospects
- Market Considerations
- Transmission Expansion

Fossil Fuels and Sustainability: Like Oil and Water?
Session Chair: Mark Jaccard, Simon Fraser University
- Decarbonating Fossil Fuels
- Sequestering Carbon
- Technology Synergies

Energy Regulation Trends and Prospects in North America
Session Chair: Michelle Foss, University of Houston
- What Kind of Markets are Being Built?
- How is Success Measured? By Price?
- How Much Restructuring is Needed for Electricity?

Vancouver, British Columbia is a wonderful and scenic/tourist place to meet. Single nights at the Sheraton Wall Centre Hotel are $224.00 Cdn. (approximately $150.00 U.S. dollars – a phenomenal rate) per night. Contact the Sheraton Wall Centre Hotel at 604-893-7120, to make your reservations). Conference registration fees are $500.00 for USAEE/IAEE members and $600.00 for non-members. Your registration fee includes two lunches, a dinner, three receptions and numerous coffee breaks, all designed to increase your opportunity for networking. Special airfares have been arranged through Air Canada. Please contact Air Canada by calling 800-361-7585 (or 514-393-9494) and reference our group #CV625181. These prices make it affordable for you to attend a conference that will keep you abreast of the issues that are now being addressed on the energy frontier.

There are many ways you and your organization may become involved with this important conference. You may wish to attend for your own professional benefit, your company may wish to become a sponsor or exhibitor at the meeting whereby it would receive broad recognition or you may wish to submit a paper to be considered as a presenter at the meeting. For further information on these opportunities, please fill out the form below and return to USAEE/IAEE Headquarters.

Energy Markets in Turmoil: Making Sense Of It All

22nd Annual North American Conference of the USAEE/IAEE

Please send me further information on the subject checked below regarding the October 6-8, 2002 USAEE/IAEE Conference.

____ Submission of Abstracts to Present a Paper(s) _____ Registration Information _____ Sponsorship Information _____ Exhibit Information

NAME: ____

TITLE: ____

COMPANY: ____

ADDRESS: ____

CITY,STATE,ZIP: ____

COUNTRY: ______________________ Phone/Fax: ______________________

USAEE/IAEE Conference Headquarters
28790 Chagrin Blvd., Suite 350, Cleveland, OH 44122 USA
Phone: 216-464-2785 Fax: 216-464-2768 Email: usaee@usaee.org

Market Fragmentation and Gasoline Price Shocks: An Investigation

*By Barry Posner**

During the summers of 2000 and 2001 the price of gasoline reached historically high levels in many parts of the United States, most notably in the Midwest. The Clean Air Act Amendments of 1990 mandated the use of different types of gasoline in geographically proximate regions, which has led to the existence of 24 different "fuel islands" in the United States, areas which use different gasoline formulations than the surrounding areas. Many feel this market fragmentation has been a cause of the price spikes.

I analyzed price data from 36 U.S. gasoline markets, and calculated the portion of the price added by the refining, transportation and marketing functions. I compared the price in each market, and in each week, to the price in the same market in the four previous years and delineated the percentage increase in markups. This was done for the years 1998-2001. This markup percentage was used to define whether or not a price shock existed. For each market, I calculated the population of the "island" in which the market was contained.

I examined the geographical extent of each price shock, and regressed the number of shocks versus the population of each island. It was hypothesized that markets in small islands would be more prone to shocks than markets in large islands. I discovered that no significant relationship between island size and number of shocks existed using the present data set. Indeed, a weak positive correlation between number of shocks and market size existed.

Shocks were shown to be primarily regional, and typically affected markets of all sizes and of all types of gasoline in a given region. No shocks existed in 1998 or 1999, but a large number did in 2000 and 2001. This leads me to hypothesize that ever-tighter production capacity constraints combined with stochastic occurrences of regional pipeline and refinery outages may be the root cause of the price shocks. I shall address this theory in future research.

Introduction

In the past two summers, there was great outcry in the Midwest concerning the price of gasoline. The price spiked up to over $2.00 per gallon in some areas - unprecedented high nominal prices. Congressional investigations were undertaken, and the results loudly trumpeted that the problem was with "boutique fuels," special blends of gasoline specific to each market. Legislation was thought to have created a balkanization of the gasoline market, and exacerbated supply crunches that occurred in the high driving season. This idea has an intuitive appeal: when the gasoline market was largely homogeneous, price differences in geographically proximate regions presented arbitrage opportunities that were seized by local distributors, thus quickly correcting regional market imbalances. Given that presently the gasoline in a certain city may not be the same as that in surrounding counties, it is more difficult for regional distributors to move to take advantage of these opportunities, and thus the arbitrage opportunities will have to be larger in order to attract movement of supply, and will take longer to correct. Therefore, local suppliers will be able to charge a premium that represents the transportation cost between the specified gasoline "island" and the closest similar "island" or producer.

This paper will examine the hypothesis that such balkanization was correlated with the price shocks observed in the summers of 2000 and 2001. I will start by listing the pertinent details of cleaner burning gasoline laws. I will define the markup component of prices - that is, the price after the cost of crude has been taken out, and before taxes added in - the net value added by the refining, distribution and retail functions of the gasoline market, and compare this markup during the past two summers with markups in 1998 and 1999. I will then define the market conditions that constitute a "price shock", and examine whether the size of the isolated gasoline "island" is correlated with the presence and persistence of price shocks.

Cleaner-Burning Gasoline Laws

As a reaction to the chronic incidences of poor air quality in many American urban areas, several pieces of legislation, both federal and state, have been passed. The most important laws governing mobile source (automobile) pollution were introduced in the 1990 Amendments to the Clean Air Act (CAA)(1). Three main clean gasoline programs exist.

Low RVP gasoline

The volatility of gasoline refers to its tendency to flash from a liquid to gaseous form. The Reid Vapor Pressure (RVP) is a measure of volatility. The lower the RVP, typically measured in pounds per square inch (psi), the less prone a gasoline is to flashing. Vaporized gasoline components react with oxides of nitrogen in the presence of sunlight to form ozone and photochemical oxidants (smog precursors). Volatility increases as temperature rises, so the U.S. Environmental Protection Agency (EPA) mandated the introduction of low RVP summer gasoline. The first phase of low RVP gasoline predates the CAA, having been introduced by the EPA in 1989 (2). Phase 2 RVP requirements were issued in 1990, revised to conform to the CAA in 1991 (3), and took effect in May 1992. Before introduction of these regulations, gasoline typically had an RVP of 11.5 psi. Under Phase II of the summer volatility program, the RVP is now 9.0 in the Northern United States, and all ozone attainment areas, and 7.8 in Southern ozone nonattainment areas. A total of 57 federally defined areas are currently in some state of ozone non-attainment, a drop from the count of 101 observed in 1989 (4).

RVP reduction is typically performed by reducing the amount of butanes in gasoline. Butanes (four-carbon molecules) are desirable for their low cost and high blending octane number, but as light ends they are very volatile. Butanes have to be replaced by higher-value high-octane components, thus increasing the cost of gasoline. The effects of the summer volatility program on refinery operation and gasoline costs are detailed by Lidderdale (5). Low RVP gasolines are mandated from June 1 to September 15.

Oxygenated Gasoline

Carbon monoxide (CO) is a colorless, odorless gas that

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(1) See references at end of text.

is very stable in the lower atmosphere, having a lifespan of two to four months (6). High ground-level concentrations exist in cold climates due to the inefficient operation of cold automobile engines coupled with thermal inversions, which trap the air at ground-level. CO is a poisonous inhalant that causes impairment and discomfort at concentrations as low as 30 ppm, and is fatal at 750 ppm. One way to combat CO formation is through the use of oxygen-containing gasolines. The oxygen in the fuel promotes more complete combustion, and reduction of tailpipe concentrations of CO. Section 211(m) of the CAA requires that gasoline containing at least 2.7 percent oxygen by weight is to be used in the wintertime in those areas of the county that exceed the CO National Ambient Air Quality Standard (NAAQS). At implementation of the winter oxyfuels program on November 1, 1992, 39 regions were designated as non-attainment areas. This number has since shrunk to 18, as of July 1, 1999, with seven more areas having filed redesignation plans. Depending upon the region, the winter oxyfuels program is typically in effect from October 1 or November 1 to February 29. Further details of the winter oxyfuels program can be found at the Energy Information Administration website (7)

Reformulated Gasoline

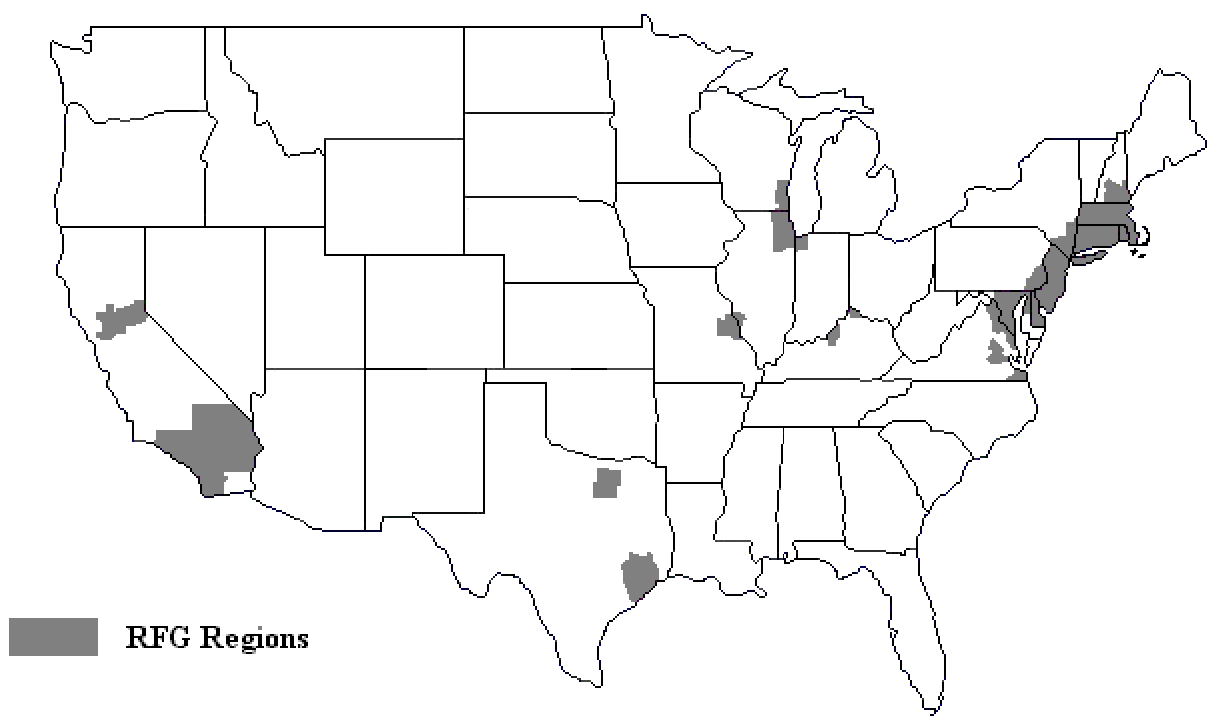
Section107(d) of the CAA requires all areas of the country to be classified according to non-attainment of the NAAQS for ozone. The classifications were marginal, moderate, serious, severe or extreme. One area, Los Angeles, was classified as extreme, and eight more were considered severe: Baltimore, Chicago, Hartford, Houston, Milwaukee, New York City, Philadelphia, and San Diego. In 1995 Sacramento, California was reclassified from serious to severe. These regions were mandated to adopt use of reformulated gasoline (RFG). Several other regions opted in to the RFG program, including Phoenix (which has since switched to more stringent California standard gasoline), Louisville, St. Louis, Dallas-Fort Worth, and almost all of the Eastern Seaboard from Massachusetts to mid-Virginia. These areas are shown in Figure 1.

RFG is manufactured according to a complex set of technical specifications designed to lower the tailpipe emissions of volatile organic compounds, oxides of nitrogen, CO, and other toxic pollutants, by significant amounts - over 20% below 1990 levels.

RFG specifications were introduced in two phases. Phase I ran from January 1, 1995 to December 31, 1999. The more stringent Phase II specifications took effect January 1, 2000. The detailed specifications can be found in the Code of Federal Regulations (8).

Specific requirements call for a reduction in benzene, a mandated oxygen content of 2.0% by weight, and low RVP requirements for the summer. Thus, the RFG program subsumes the oxygenate and low volatility requirements into a more rigorous set of requirements. For the refiner, this creates a much more stringently defined product. Gasoline will increase in cost due to the displacement of benzene, a common and cheap source of octane, of butane, as mentioned above, the addition of oxygenate, and the requirement for lower-polluting fuel in general. This entails more extensive preparation and modification of the crude feed, with ensuing increases in energy input and capital expenditure. More details of the RFG program can be found at the EIA website (9). It was anticipated that the implementation of the RFG provisions of the CAA would have economic impacts on gasoline consumers. Two cost issues were addressed by the EPA. First, a broad-based analysis of program implementation costs was undertaken (10), addressing the expected price rise from an industry cost perspective. Second, a study of the

Figure 1
Federal Reformulated Gasoline Areas



efficiency losses due to increased fuel consumption was performed (11). However, a third avenue of negative cost effect appears to have been unanticipated: exposure of the consumer to a cost increase due to balkanization of gasoline markets.

Midwest Price Spikes and RFG

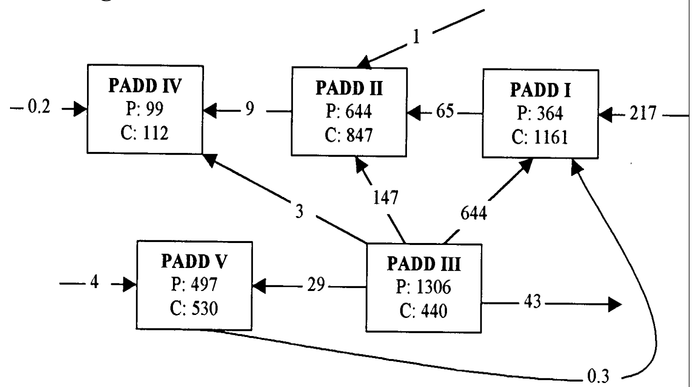
The summers of 2000 and 2001 saw drastic spikes in the prices of gasoline, most noticeably in the Chicago and Milwaukee areas, where retail prices reached as high as $2.75 per gallon. This attracted the attention of politicians and regulators. Both the Congressional Research Office (12) and the Federal Trade Commission (13) published reports about the price spikes. Neither report found any evidence of illegal behavior, but both mentioned the prevalence of boutique gasolines as a contributing factor: with the various combinations of winter oxygenate, summer volatility and RFG requirements, it has been estimated that there are as many as 38 mandated varieties of gasoline for sale at any time in the United States. This is a drastic change from the pre-CAA days, when gasoline was largely a homogeneous commodity, with variations for altitude and seasonality being the only differentiating factors. This meant that a shortage in one area could be easily addressed by transferring supply from a geographically proximate area. Stated in economic terms, there were low transaction costs to moving gasoline. The new laws have changed this. For example, if a shortage of reformulated gasoline crops up in Louisville, it is not possible to simply ship in gasoline from rural Kentucky or Cincinnati or Memphis, which use conventional gasoline, but instead supplies must come from St Louis or Chicago, and those markets may be encountering similar supply crunches. Therefore, the supply shortfall must be remedied by custom-ordered production increases in refining centers, such as the Gulf Coast, which must then be shipped long distances via pipeline and barge. Transaction costs have been greatly increased, as have transfer times, and thus it is hypothesized that shocks will persist for longer periods, and will be more severe. The EPA has issued two reports about boutique fuels, addressing blending and feedstock concerns, and transitional difficulties (14, 15). These reports do not mention market fragmentation.

The Regional Structure of the U.S. Gasoline Market

Figure 2 displays the production, consumption and inter-regional trade in gasoline in the USA. The five blocks labeled PADD I through V refer to the Petroleum Administration for Defense Districts, as defined by the Department of Energy for analysis purposes (and distribution in the case of national emergencies). The "P" term inside each block refers to gasoline produced in that PADD, and the "C" term refers to consumption in that region. The numbers overlying the arrows define the net flows between PAD districts and net imports from other countries. All amounts are in millions of barrels. Data are for the year 2000, and were downloaded from the 2001 Petroleum Supply Annual (16), published by the EIA.

As can be seen, PADD III (Gulf Coast) is the prime refining region in the country, supplying large shares of the Midwest and East Coast markets. PADD I imports about 15% of its consumption from overseas, and supplies PADD II with about 8% of its consumption. PADD V (the West Coast) is

Figure 2
Regional Structure of the U.S. Gasoline Market



remote from the rest of the system: there are very few linkages between this district and the rest of the country, either by pipeline or other mode of transport. Price behavior in PADD V is largely independent of that in the other districts, and as such it is typically treated as a separate country for purposes of analysis. This practice has been adopted for this report: henceforth, only market behavior in PADD's I-IV will be examined.

The Economic Model

Classical microeconomic theory tells us that in a perfect market, a large number of suppliers will behave as price-takers, and will drive prices down to the long-run average cost (LRAC). As markets become smaller, and the number of suppliers decreases, suppliers begin to develop market power, or the ability to charge prices above LRAC. The CAA gasoline provisions have fractured the U.S. gasoline market from one largely homogeneous market to several smaller, differentiated ones. At the same time, the number of refiners in the United States is shrinking. According to the above theory, these conditions should combine to increase price above LRAC. How can market power be modeled in this context?

The price of gasoline is strongly affected by the price of crude oil. A quick analysis of the spot market prices of crude oil (17) and regular-grade conventional gasoline (18) reveals that crude typically represents about 70-80% of the refiner's cost of gasoline, and is by far the most price-volatile of all inputs. A simple regression of gasoline spot price on crude spot price (from June 1986 through December 2001) reveals a relationship of the form: Gasoline Price = 4.2 + 1.12 x Crude Price, where prices are in cents per gallon. This equation has an R^2 value of 0.86, reflecting a high degree of correlation between the two prices. It is more revealing to look at the difference between crude prices and gasoline prices. The price of crude oil and the taxes levied on gasoline do not change with demand, and thus are assumed to be exogenous. We wish to examine the endogenous part of the cost of gasoline - the price with crude costs and taxes excluded.

I refer to this difference as the gasoline markup, which is the main focus of this study. The markup must cover a wide variety of costs. The *Oil and Gas Journal* (OGJ) tracks refiner and retailer margins, and Spletter and Starr, in the OGJ (19) have identified the following cost components:

Refiner costs: crude oil transportation (FOB location to refinery); crude oil inventory and storage; chemicals and catalysts; blending component purchase and storage costs; energy inputs (natural gas, electricity); labor costs; marketing costs; corporate taxes; refiner profit.

Distributor costs: transportation (refinery to terminal); terminal operations expenses (labor, energy, rent, income taxes); inventory and storage costs; additive costs (methanol); blending costs; distributor profit.

Retail costs: transportation (terminal to retailer); storage; labor; energy costs; rent; maintenance; retailer profit.

Clearly, many costs must be borne by the margin between crude cost and tax-out retail price. Of the above components, many are fixed in the short run: there are no significant short run changes in chemical and catalyst prices, equipment costs, rents or wages. Energy and transportation costs can vary according to the price of crude, but it is hypothesized that the swings in the markup are created by firms with market power exercising that asset: the markup goes up as demand increases and supply decreases.

Gasoline has a low short-run price elasticity of demand. Several authors, including Archibald and Gillingham (20), Puller and Greening (21), Molly (22), Kayser (23) and Rao (24) have shown that the short run elasticity is between -0.01 and -0.08. Assuming a median value of -0.04, this means that a 10% increase in the price of gasoline will result in reduced demand of 0.4%, or that a doubling of price will lead to a consumption drop of only 4%. This fact is well established and guides refiner and retailer behavior: they know that price increases related to demand increases will not invalidate those demand increases: a stable equilibrium arises at a higher priced supply-demand intersection.

It is hypothesized that the price of gasoline, net of taxes and crude prices, should be correlated to market power, and market power will be proxied by the size of a given gasoline market. This study shall attempt to define whether price shocks, which are assumed to be exercises of market power, are correlated with the size of the market. That is, has the balkanization of the national gasoline market led to a meaningful increase in market power?

The Econometric Model

Markets and Periods Studied

Weekly tax-out price data for 36 U.S. markets were recorded from the *Oil and Gas Journal* (25) for the eight-year period spanning 1994-2001. The markets are listed in Table 1, sorted by PAD District. These data are collected once per week by OGJ staff, and reflect an average price for regular unleaded gasoline over several urban and suburban gas stations in each market.

The Dependent Variable

Gasoline prices exhibit hysteresis when measured against crude prices. That is, the price of gasoline rises on news of crude price rises quicker than it falls in response to crude price drops. This is known as “downward sticky” behavior, and has been examined by, among others, Borenstein, et al. (26). It has been observed that crude price increases are almost instantaneously passed through to gasoline prices, but crude price drops typically lag by 4-8 weeks. Retailers are forward looking: when crude goes up, the retailer can expect to pay a higher price to replace his existing stock, and thus will raise the price of his current stock to his expected next purchase price. However, when crude prices drop the retailer is in possession of gasoline that was purchased at a higher price than that which will be available in the near future. Thus, the retailer keeps his price high enough to recoup costs of his existing inventory, and will only drop prices when new, lower cost inventory is obtained. Prices begin to come down when some retailer in a market exhausts his inventory of high-price gasoline and obtains a new, lower-cost shipment. Thus, gasoline prices are typically correlated to the maximum price of crude oil over some lagged period.

Table 1: Markets of Study

PADD I	PADD II	PADD III	PADD IV
Atlanta	Chicago	Albuquerque	Cheyenne
Baltimore	Cleveland	Birmingham	Denver
Boston	Des Moines	Dallas-Fort Worth	Salt Lake
Buffalo	Detroit	Houston	
Miami	Indianapolis	Little Rock	
Newark	Kansas City	New Orleans	
New York	Louisville	San Antonio	
Norfolk	Memphis		
Philadelphia	Milwaukee		
Pittsburgh	Minneapolis		
Washington, DC	Oklahoma City		
	Omaha		
	St. Louis		
	Tulsa		
	Wichita		

To take the hysteresis effect into consideration markup was modeled as the difference between current gasoline prices and the maximum cost of crude in the past six weeks. Symbolically,

$$MU_{i,t} = PG_{i,t} - \text{Max}\ \{PC_{t-5}, PC_{t-4}, PC_{t-3}, PC_{t-2}, PC_{t-1}, PC_t\} \qquad \text{(i)}$$

where $MU_{i,t}$ is the markup in market i at time t, in cents per gallon,

PC_t is the Cushing, OK spot price of crude at time t, in cents per gallon,

$PG_{i,t}$ is the tax-out retail price of gasoline in market i at time t, in cents per gallon.

The markups were then inflation-adjusted using the monthly Bureau of Labor Statistics Transportation Cost Index (27), with January 1994 as the base period. They were sorted into annual bins for each of the 36 markets, and then a “Shock Index” for each week in the years 1998-2001 was calculated. This is defined as follows:

$$S_{i,w,y} = 100\frac{4 \times MU_{i,w,y}}{\sum_{j=1}^{4} MU_{i,w,(y-j)}} - 100 \qquad \text{(ii)}$$

where $S_{i,w,y}$ = “shock index” in market i, week w and year y, in percent

$MU_{i,w,(y-j)}$ = markup in market i, week w and year y, cents per gallon

Thus, the shock index is simply this year’s markup divided by the average markup in the same market, and same week of the year, over the previous four years. A market was assumed to be under gasoline price shock conditions if the value of “S” was greater than 50%, that is, if the gasoline markup was more than 50% higher than the four-year average price in the given period. Clearly, this is an arbitrary definition, but I assumed that if the combined real take of the refiner, transporter and merchant was over one and a half times his expected take based on the previous four years, it can be safely assumed that market power is being exercised.

The number of weekly occurrences of shocks were then tabulated and summed over the four-year period of study for the 36 markets in question. This sum is the dependent variable in this model: the number of weeks under shock conditions.

The Independent Variable

The size of each individual market is the independent variable in this model. Ideally, sales for each region would be used as the variable, but sales data by county, and hence by region, are unavailable in the public domain. The greatest degree of disaggregation reported by the EIA is by state (spatially) and by month (temporally). For this reason, I decided to use population as a proxy for sales, primarily because population data to match the exact boundaries of the different gasoline regions are available. The one nuance that is lost by this method is that different regions have different sales patterns, for example, farm-intensive regions have much greater seasonal variations, as do cold-weather regions. Year 2000 population data for each county in the United States were obtained from the U.S. Census Bureau (28). For each county in PAD Districts I-IV, the type of gasoline sold in the summer was listed. The different types of clean gasoline, reformulated, low RVP or oxygenated, were then arranged into contiguous regions, with each region forming an "island". The "sea" surrounding these islands consists of all of the areas selling conventional gasoline. The population was summed over each county within each contiguous region. This population of the region in which each of the 36 study markets falls into, measured in million of people, is the independent variable. Thus, the regression estimated in this study is:

$$\Sigma S_i = \beta_0 + \beta_1(P_i) + \varepsilon_I \qquad \text{(iii)}$$

Where ΣS_i = number of weeks under shock conditions in market i

P_i = Year 2000 population of region in which market i is contained

β_0, β_1 = empirically derived parameters

Data Conditioning Results

Price Shock Data

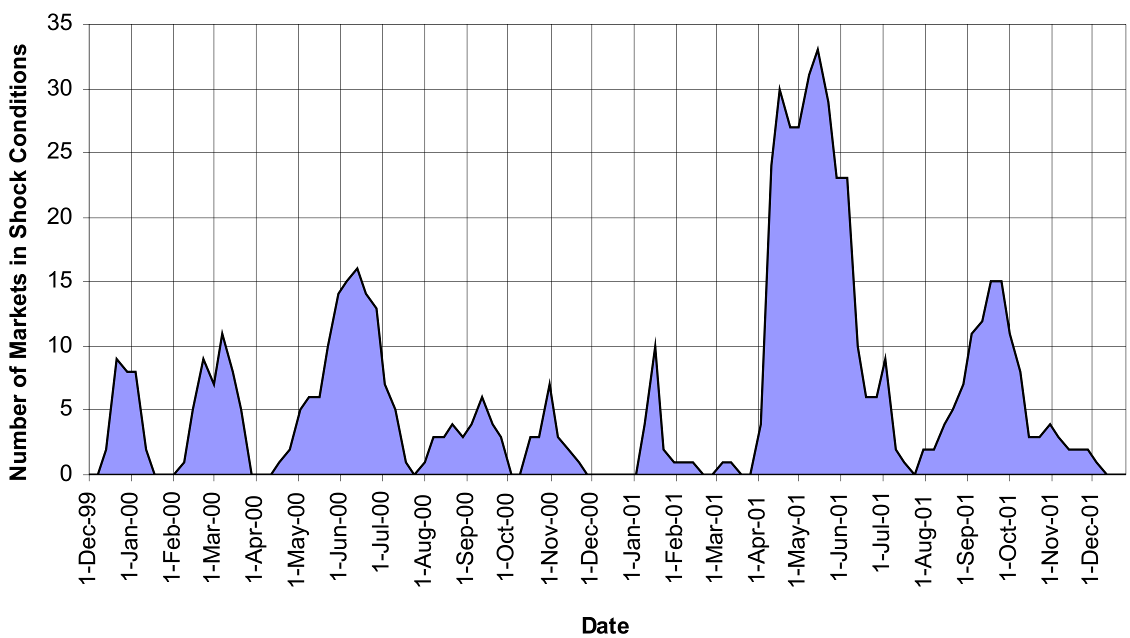
The sales price data were manipulated as described above, and the total number of weeks in the four-year period under shock conditions were calculated. The results are shown in Table 2. The number of markets under shock conditions for each week of this study is shown in Figure 3. There were no meaningful shocks in 1998 or through most of 1999 - any disturbances were limited to one or two markets, and were corrected in one or two weeks. Figure 3 begins at December 1999 and runs through December 2001. As can be seen, there are eight distinct "peaks", each corresponding to a shock that affected at least six markets and lasted for at least four weeks. These shocks will henceforth be labeled as shocks 1 through 8, and each will be described individually. The characteristics of each shock are detailed in Table 3.

Shock 1 was broadly dispersed, and was observed in Cleveland, Detroit, Kansas City, Oklahoma City, Wichita, Albuquerque, New Orleans, Cheyenne and Salt Lake City. This shock is hard to quantify: it is not concentrated in any particular region, and is broadly dispersed.

Shock 2 is confined to the central and southern regions of PADD I and PADD II. It does not reach as far north as Chicago or as far as Texas, but is fairly continuous over a "heartland" belt stretching from Atlanta to Wichita.

Shock 3 was the first shock to generate widespread attention. This took in almost all of PADD II, and existed in a less durable fashion through most of PADD III and the southern regions of PADD I. It did not reach the Northeast or PADD IV. While the price effect was publicized mostly in Chicago, the percent increase over normal markups was greatest in the small cities of the Corn Belt, sometimes reaching double previous levels.

Figure 3
Gasoline Price Shock Occurrences



Shock 4 was a small follow-on to shock 3. It occurred primarily in the central regions of PADD III and Atlanta. Oddly it was also felt in Philadelphia, but no other Northeast city.

Table 2
Number of Weeks Under Gasoline Price Shock Conditions

Market	PADD	Number of "Shock" Weeks
Atlanta	I	51
Baltimore	I	15
Boston	I	14
Buffalo	I	9
Miami	I	6
Newark	I	18
New York	I	7
Norfolk	I	9
Philadelphia	I	27
Pittsburgh	I	5
Washington, DC	I	8
Chicago	II	19
Cleveland	II	33
Des Moines	II	34
Detroit	II	36
Indianapolis	II	17
Kansas City	II	19
Louisville	II	15
Memphis	II	6
Milwaukee	II	21
Minneapolis-St. Paul	II	23
Oklahoma City	II	37
Omaha	II	27
St. Louis	II	20
Tulsa	II	27
Wichita	II	23
Albuquerque	III	5
Birmingham	III	15
Dallas-Fort Worth	III	20
Houston	III	38
Little Rock	III	24
New Orleans	III	7
San Antonio	III	2
Cheyenne	IV	10
Denver	IV	33
Salt Lake City	IV	4

Shock 5 was widely dispersed, like shock 1. It mildly affected markets as diverse as Boston and Wichita, but persisted for over a month in Dallas and Houston.

Shock 6 was another small mid-winter event. It occurred in cold climates, ranging from Buffalo to Cheyenne. It only persisted for any length of time in Des Moines.

Shock 7 was the successor to the big shock of 2000. This event was felt in every region, and every city except New Orleans and Salt Lake City (and was barely visible in San Antonio and Albuquerque). It was also accompanied by the most severe price rises in many cities, and persisted for months in the Northeast and Central areas.

Shock 8 was basically a continuation of shock 7 centered mostly in the Northeast and northern Midwest, but it also spread as far southwest as Tulsa.

Gasoline Island Definition

The results of the calculation of region definition are shown in Table 4. As can be seen from Table 4, regions 1 to 24 comprise the "islands" in the sea that is defined by region 25.

Table 3
Details of Gasoline Price Shocks

Shock No.	Onset	Length (weeks)	Peak Spread (markets)
1	December 1999	5	9
2	February 2000	7	11
3	April 2000	14	16
4	August 2000	9	6
5	October 2000	6	7
6	January 2001	6	10
7	April 2001	16	33
8	August 2001	19	15

Table 4
Gasoline Regions

No.	Region Name	Study Markets in Region	Fuel Type	Population
1	Atlanta	Atlanta	Low RVP	3,634,702
2	Birmingham	Birmingham	Low RVP	818,021
3	Charlotte	None	Low RVP	876,988
4	Chicago	Chicago, Milwaukee	RFG	10,528,712
5	Covington	None	RFG	324,273
6	Detroit	Detroit	Low RVP	4,879,448
7	Dallas	Dallas-Fort Worth	RFG	4,478,706
8	Houston	Houston	RFG	4,674,814
9	Jacksonville	None	Low RVP	781,055
10	Kansas City	Kansas City	Low RVP	1,526,544
11	Louisville	Louisville	RFG	735,608
12	Maine	None	Low RVP	1,274,915
13	Memphis	Memphis	Low RVP	905,755
14	Miami	Miami	Low RVP	5,034,956
15	Minnesota	Minneapolis-St. Paul	Oxygenated	4,919,436
16	Nashville	None	Low RVP	1,076,684
17	New Orleans	New Orleans	Low RVP	2,460,800
18	Northeast	Boston, New York, Newark, Philadelphia, Baltimore, Washington	RFG	45,250,379
19	Pittsburgh	Pittsburgh	Low RVP	2,461,874
20	Central NC	None	Low RVP	1,779,414
21	Salt Lake	Salt Lake City	Low RVP	1,336,938
22	St. Louis	St. Louis	RFG	2,505,842
23	Tampa	None	Low RVP	1,923,843
24	Norfolk	Norfolk	RFG	1,513,949
25	Rest of PADD I- IV	Buffalo, Cleveland, Des Moines, Indianapolis, Oklahoma City, Omaha, Tulsa, Wichita, Little Rock, San Antonio, Cheyenne, Albuquerque, Denver	Conventional	123,562,238

Regression Results

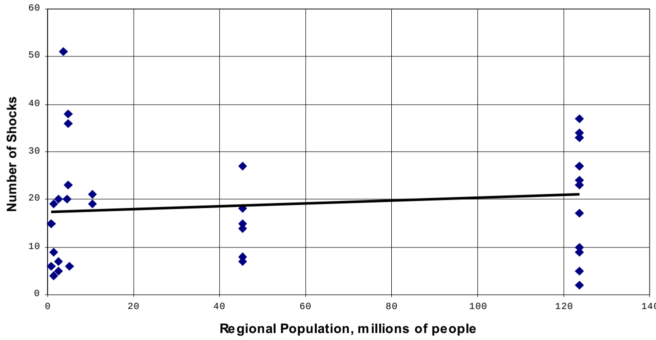
Figure 4 shows the sums of shocks per market (as defined in Table 2) plotted versus the population of each market's home region population, as well as the best-fit line. The shocks were regressed against the population, with the following results (standard error in parentheses):

$$\Sigma S_i = \underset{(2.78)}{17.36} + \underset{(0.036)}{0.030}\, P_i$$

The t-statistic the slope parameter is 0.832, and the R^2 for this regression is 0.020.

If one expects that arbitrage opportunities will persist mostly in small markets, then one would expect a larger number of shocks in these markets, and we would thus expect the regression to have a negative slope. In other words, a best-fit line will slope downwards. The hypothesis is formally framed as follows:

Figure 4
Number of Shocks versus Regional Population, All Markets



Null hypothesis: H_o: $\beta_1 < 0$
Alternate hypothesis: H_a: $\beta_1 \geq 0$

Given examination of the t-statistic of β_1, as well as the extremely low R^2 value, and the positive slope of best-fit line in Figure 4, we can safely reject the null hypothesis, and state that given the evidence at hand, there is no reason to believe that the slope of the best fit line is significantly different to zero, and thus no structural relationship between market size and number of shocks exists in the current data samples.

We may choose to look at only the data for small-markets, that is, reject the data for the "Rest of PADD I-IV" and the Northeast, and look at the relationship in smaller markets. These data, and the best-fit line, are plotted in Figure 5. The results for this regression are as follows:

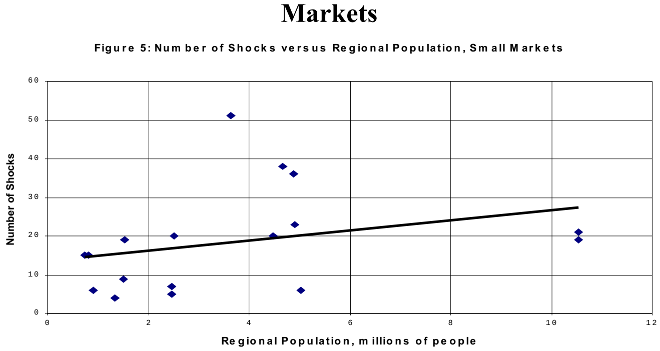
$$\Sigma S_i = \underset{(5.05)}{13.76} + \underset{(1.073)}{1.295}\ P_i$$

The t-statistic the slope parameter is 1.21, and the R^2 for this regression is 0.089. The t-statistic and R^2 have improved, but not to levels that could be considered significant, and the slope is still positive.

Analysis

Based on both econometric estimation and descriptive analysis of the price shocks, it is clear that market size is not a determining factor, at least from the perspective of arbitrage opportunities being more prevalent in small markets. The large shocks were regional in nature, and equally affected both large and small markets and both reformulated and conventional gasoline markets. The largest shocks affected more than one PAD District, and this is not surprising given the inter-regional dependencies shown in Figure 2.

Figure 5
Number of Shocks versus Regional Population, Small Markets



A refinery outage in PADD III will have effects on PADD I, II and III, with PADD IV being more immune to shocks than the other regions. A production interruption that is native to PADD I or II may only affect the home region, but if the shortfall is significant enough then demand-driven price pressure may extend back to PADD III. What is obvious is that price shocks seldom affect any region in isolation. This explains why the higher arbitrage theorem may be invalid: when an upset occurs in a market, then to seize this arbitrage opportunity an entrepreneur will want to ship product from the closest possible "same-product" market. However, if the shock has spread to that market, then no arbitrage opportunity exists, and one has to go further afield to find an unaffected market to capitalize upon. The further away the unaffected market, then the greater the transportation cost, and the longer the time required to deliver the product. Both of those factors will exacerbate the size and duration of shocks in the affected markets.

We must also consider that the possibility that the larger the affected market, the larger the arbitrage opportunity, and thus the larger the shock. This is in direct contradiction to the hypothesis upon which this paper is based. However, once again the largest markets, in the Northeast and the upper Midwest, are the furthest away from the refining hub in the Gulf, so it takes longer to get relief product into those markets, and a greater volume of product is required to satisfy demand in those markets.

One unexplained observation is the fact that minimal shocks were observed in 1998 and 1999, but many severe ones were in 2000 and 2001. On the surface, little is different between these two periods: Low-RVP gasoline requirements were the same in all markets, and reformulated gasolines were required in both periods. There was a shift from Phase I to Phase II RFG on January 1, 2000, but this did not effect market differentiation in any way. One explanation, contained in the FTC Investigation (13) is that unexpected pipeline and refinery shutdowns, coupled with capacity constraints, caused regional upsets which rapidly propagated through the entire PADD II region in 2000 and the entire nation in 2001.

Conclusions and Recommendations for Further Work

As discussed above, the model as specified does a poor job of demonstrating that regional population is a significant and meaningful predictor of the presence of gasoline price shocks. The next stage in the development of this model is the incorporation of capacity constraint effects. These appear to be strongly non-linear, and as such an appropriate non-linear specification must be devised. Additionally, a better measure of market size may be helpful. Using a static value of population does little to capture seasonal shifts in demand that may have an effect on price, and differences in regional consumption patterns are not elaborated.

A better definition of market power can be established by looking at the links between specific refineries and markets: how many refineries serve each market, how close to peak market demand is the capacity of those refineries, and how easy are alternative supplies to find in the presence of unexpected refinery or pipeline outages?

I have also largely overlooked competition in the retail sector in this report. One might be better able to model the price response of this sector given more information about the number of major oil companies in each market, the number of independent retailers, and the ease of availability of branded gasolines in the various markets.

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International Association for Energy Economics 2002 Student Scholarships

The IAEE Council is seeking nominations for 2002 IAEE Student Scholarships. These scholarships have been established in order to reward and support the studies of outstanding students of energy economics, especially those resident in emerging economies.

It is planned to make 3-5 awards of US$1000 each for 2002. The successful recipients will be studying energy economics or a related energy discipline at an internationally recognised university. They will also receive free membership in the IAEE for five years and admission to one IAEE international conference between 2002 – 2003.

The awards will be made by a committee of IAEE Council members comprising of Dr. Michelle Foss (University of Houston), Prof. Jean-Philippe Cueille (Institut Français du Petrole) and Dr. Arnold B. Baker (Sandia National Laboratories). Their decisions will be final. A list of award recipients will be published in the ***IAEE Newsletter***.

Applications should be accompanied by a brief explanation as to why the applicant considers him/her self worthy of the award together with a letter of recommendation from the student's advisor (in confidence if desired) – two separate letters are needed. Applications will close 21 October 2002 and awards will be announced by 29 November 2002.

Applications for scholarships should be mailed or emailed to:

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28790 Chagrin Boulevard, Suite 350
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Email: iaee@iaee.org

Caspian Sea is No Middle East

*By Mamdouh G. Salameh**

Introduction

A lot has been written about the oil potential of the Caspian Sea. Some sources described it as the "great prize" while others talk of it as if it were a new Kuwait. Fanciful estimates have claimed that Caspian Sea oil reserves rival those of the Arab Gulf. Others have ascribed potential recoverable reserves of 200 billion barrels (bb) to the area.[1] The Caspian Basin has been over-promoted by some as a new Middle East, and as an alternative global supplier to the Arab Gulf. Others, by contrast, see it as an overstated high-risk oil province that will, to a large extent, remain isolated from world markets. The reality, as always, is somewhere in between.

Caspian Sea's proven reserves are at present estimated at less than 17 bb, or 1.5% of the world's total proven reserves.[2] However, there is now some confidence in the view that the proven oil reserves of the Caspian fall within the range of 18 bb-20 bb. The bulk of these reserves lie within the North Caspian Basin. Drilling failures in the South Caspian Basin and a comprehensive geological appraisal suggest that there is little further prospect of new oil, even in untested deepwater traps of the South Caspian, which are currently subject to territorial dispute. By 2010 the Caspian should be producing some 3 million barrels a day (mbd), two-thirds from the North and one-third from the South. However, this depends on a timely investment in new Caspian support infrastructure and the ability of western oil investors to access large-scale project financing.[3]

Apart from the limited size of the reserves, Caspian oil is very costly to find, develop, produce and transport to world markets. The Caspian Sea is practically a landlocked area, and the economic and geopolitical problems arising from transporting the oil by pipelines through other countries add to the risks of investments there.[4]

With these apparent disadvantages of the Caspian Sea oil in mind, a puzzling question arises: why the rush of so many American and international oil companies to invest in this region? Under normal market conditions, investors would naturally turn to the abundant, low-cost oil of the Arab Gulf, rather than to these high-cost, politically hazardous areas.

Why Invest in the Caspian Sea?

With the collapse of the former Soviet Union, the Caspian Basin presented western oil companies with a unique opportunity to acquire huge oil reserves at low technical risk. These companies also recognized that these reserves were located in a region where both political and business risks were unexpectedly high. The newly independent Caspian republics saw western oil investment as a safeguard for their newly-won independence from Russia.

Consequently what drove the original western energy investment in the Caspian was access to three proven but undeveloped ex-Soviet super giant oilfields: Tengiz and Karachaganak in Kazakhstan, and Azeri-Chirag-Guneshli in Azerbaijan. These three fields still dominate the Caspian energy scene today, with the addition of two new super giant oil and gas discoveries at Kashagan in Kazakhstan and Shah Deniz in Azerbaijan.

Apart from the economics of investing in Caspian Sea oil, political motivation has been an important factor. The declared U.S. policy has been to encourage investing in the Caspian, and to create United States interests in the geopolitically sensitive area situated near both Iran and Russia. It is also a declared policy of the United States to develop Caspian Sea oil in order to reduce dependence on oil from the Arab Gulf, which is still viewed as an unstable region where the outbreak of revolutions or wars could again interrupt oil supplies and cause price shocks.[5]

For the United States, the support of Caspian oil development began as an outgrowth of a national energy policy that calls for the expansion of oil production in areas outside the Arab Gulf.[6] The U.S. policy subsequently evolved over time to one which came to embrace three main policy goals in the region:

- Support for the sovereignty and independence of the Caspian newly-independent States (NIS).
- Enhancing commercial opportunities for the United States and U.S. companies.
- Building economic linkages (e.g., pipelines) between these states as a way of benefiting countries of the region and reducing regional conflicts.

In pursuing these objectives, the United States supports the establishment of an east-west energy transit corridor comprised of a network of multiple pipelines that will bring Caspian oil to world markets while bypassing the potential choke-point of Iran and also reducing dependence on Russian oil pipelines. This network includes a proposed Baku-Tbilisi-Ceyhan (BTC) pipeline for transporting oil from Azerbaijan to the Turkish Mediterranean port of Ceyhan, the Caspian Pipeline Consortium (CPC) that connects the giant Tengiz oilfield in western Kazakhstan to the Russian port of Novorossiysk on the Black Sea, the new early-oil pipelines from Baku to Supsa and Novorissiysk, and a trans-Caspian gas pipeline stretching from Turkmenistan to Turkey.[7]

However, political factors aside, the rush to Caspian Sea oil was spurred on by the oil market perceptions in the aftermath of the collapse of the former Soviet Union (FSU) and which lasted until 1998. These perceptions revolved around: the ability of OPEC to stabilize oil prices at artificially high levels and for a long period, the oil technology revolution that led to a spectacular reduction in the cost of finding and developing high-cost oil, the robust global oil demand between 1994 and 1997 and the fact that most OPEC countries were at that time persistent in shunning foreign investment in their national oil industries. All these favourable factors and market perceptions justified economically the rush to the Caspian Sea.

Caspian Sea Oil Reserves

The proven oil reserves of the Caspian region (Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan) amount to 17 bb. This makes the Caspian equivalent to a superior North Sea

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[1] See footnotes at end of text

and not to the Arab Gulf or even Kuwait.[8]

Estimates of 40 to 60 bb as the ultimate reserve base of the Caspian region are judged to be reasonable by most geologists familiar with the region. The latter figure requires drilling to take place. But drilling requires huge investments and huge rigs that have to be transported over excruciatingly difficult routes.

From this reserve base one can safely predict that by 2010 the Caspian should be producing between 2-3 mbd. Continued Caspian oil investment will still have to depend on three factors: first, a global oil price in excess of $20/b (in real terms); second, the absence of major political dislocations; and third, the need to address with some urgency the serious deficiencies of Caspian energy support infrastructure.

With a long-term production potential that would contribute roughly 3% to future global oil supply, the Caspian will never be a strategic alternative to the Arab Gulf. Still, the Caspian is destined to play a supporting role rather than a deciding one in supplying the world oil market in the future. By 2020, production could potentially reach 5 mbd. But this will only happen if there is a significant improvement in both the business and political risk environment in the region.

Production and Export Potential

In 2000, total Caspian oil production reached 1.37 mbd with net oil exports amounting to 665,000 barrels a day (b/d).[9] However, an IEA 1998 study on Caspian oil and gas presented two scenarios for oil production, domestic consumption and export potential of the Caspian region over the period 2000-2020.[10]

In the high case scenario, total Caspian production increases from 1.38 mbd in 2000 to 3.89 mbd in 2010 and 6.18 mbd by 2020. Net exports are projected to increase from 665,000 barrels a day (b/d) in 2000 to 2.34 mbd in 2010 and 3.57 mbd by 2020 (see Table 1). The high case scenario assumed implementation of present projects without delay, to be followed by additional development projects.

Table 1
Oil Production, Consumption & Net Exports
(High Case-mbd)

	2000	2005	2010	2020
Production	1.38	2.45	3.89	6.18
Consumption	0.52	1.26	1.55	2.61
Net exports	0.66	1.19	2.34	3.57

Sources: IEA's Caspian Oil & Gas/BP Statistical Review of World Energy, June 2001.

In the low case scenario production rises to 2.77 mbd in 2010 and 4.84 mbd in 2020. Exports also rise to 1.51 mbd in 2010 and 2.98 mbd in 2020 (see Table 2). Because of uncertainties in the timing of large projects yet to be implemented in Azerbaijan and Kazakhstan, the largest gap between the high and low scenarios for oil exports is in 2010.

Table 2
Oil Production, Domestic Consumption & Net Exports
(Low Case-mbd)

	2000	2005	2010	2020
Production	1.38	1.93	2.77	4.84
Consumption	0.52	1.06	1.26	1.86
Net exports	0.66	0.87	1.51	2.98

Sources: IEA's Caspian Oil & Gas/BP Statistical Review of World Energy.

How do these projected export figures for the Caspian Sea compare with exports of other OPEC and non-OPEC producers? In 2000 Caspian oil exports amounted to 665,000 b/d and non-OPEC producers exported 7 mbd. OPEC exports from the Arab Gulf, on the other hand, were 18.94 mbd (see Table 3).

Table 3
World Crude Oil Exports
(mbd)

Country/Region	2000	2020
North Sea	4.15	3.70
FSU	4.27	5.60
Other non-OPEC	7.00	3.80
OPEC:	27.70	51.10
Arab Gulf	18.94	41.80
North Africa	2.73	2.70
West Africa	3.29	2.30
South America	2.74	4.30
Caspian Sea	0.66	3.60

Sources: *BP Statistical Review*, June 2001 / IEA's Caspian Oil & Gas / Author's projections.

In 2020, Caspian oil exports are projected to reach 3.6 mbd (high case) or 2.98 mbd (low case) compared with 41.8 mbd from the Arab Gulf. In no case would Caspian exports in 2010 or in 2020 measure up to the very large exports from the Arab Gulf.

Caspian Oil Export Routes

The past five years have seen considerable success in the development of transportation options for oil in the Caspian region. Some 800,000 b/d (40 mt/y) of oil export capacity is already available, with an additional 600,000 b/d (28 mt/y) added with the commissioning of the CPC in October 2001 (see Table 4). Oil pipeline capacity is projected to rise to 2.4 mbd (120 mt/y) with the eventual completion of the BTC pipeline in 2005.

Table 4
Current & Projected Caspian Oil Pipeline Capacity
(000 b/d)

Pipelines	Current Capacity	Projected Capacity
CPC (Tengiz-Novorossiysk)	600	1,600
BTC (Baku-Tbilisi-Ceyhan)	-	1,000
Baku-Novorossiysk	600	600
Baku-Supsa	200	200
Baku-Tabriz (Iran)	Proposed	250
Tengiz-Uzen-Kharg (Iran)	Proposed	500
Total Capacity	**1,400**	**4,150**

Sources: Various.

However, the new CPC pipeline faces a number of difficulties. Turkey is uneasy about increased traffic through its already congested Strait of Bosphorous that connects the Black Sea with the Mediterranean and may apply restrictions to the number of vessels using this route. The other major consideration is that use of the CPC pipeline still leaves Kazakhstan dependent on Russia.

Another export route planned for Caspian crude oil is the 1,730-kilometer Baku-Tbilisi-Ceyhan (BTC) pipeline. Construction is expected to start in June 2002 and the pipeline is projected to transport 1 mbd. The United States and Turkey have long been pushing the BTC route, and the Kazakhstan government seemed enthusiastic about it at the time. But with cheaper options emerging, the country's support for the BTC route seemed to waver. Kazakhstan has been leaning toward the Iran route as the most cost-effective for Kazakhstan crude.

A southern outlet for the Caspian Basin's oil through Iran is the route most favoured by the international oil companies. It is by far the least costly option as there already exists an oil pipeline infrastructure in Iran. The 240-km Nekha-Tehran oil pipeline with a capacity of 175,000 b/d, which is expected to come online by 2003, would allow for oil swap operations.

Significant volumes will eventually move south to Iran (up to 500,000 b/d), for oil swaps from the Gulf. Caspian crude is sold to refineries in northern Iran for internal domestic markets and paid for in volumes of Iranian crude delivered at an export terminal in the Gulf for onward sale by Caspian producers in international markets. Both parties thereby benefit from saved transportation costs across Iran. Iran will, however, always be a market for Caspian oil. But until the United States softens its stance on Iran and lifts the sanctions, an Iran route will not be in the cards.

Caspian Sea Oil & World Oil Prices

The future of the Caspian Sea and its impact on Gulf oil will depend crucially on oil prices and on the investment policies of the major producers of the Gulf region itself. If low price levels of $13-$14/b persist in the coming five to seven years, Caspian oil will have little chance of expanding. By contrast, if financial pressures in OPEC succeed in restoring an artificially high price of $18/b and above, Caspian Sea oil will have every chance of expanding to a similar extent as the North Sea.

Today a fully built-up cost for the Caspian barrel of oil is roughly $12-$15/b.[11] This compares well with the North Sea but is still some three to four times more than the equivalent barrel in the Arab Gulf. Nevertheless, future Caspian built-up costs should fall to within $10/b. Progress in Caspian oil development is still heavily dependent on a sustainable $20/b (real) oil price and above. It is from within this price that a minimum of $2/b profit margin for the oil companies can be secured, with the share of profits being 80% in favour of the host governments. What happens to the price of oil will be crucial in determining the size of Caspian oil and its contribution to world oil supplies.

Impact of Caspian Oil on OPEC and World Oil Market

It has been suggested that the huge oil potential of the Caspian Basin represents a major challenge to the supremacy of the Arab Gulf as a pivotal supplier of oil to world markets and calls into question the wisdom of Arab Gulf production cutbacks designed to boost oil prices. While higher oil prices will undoubtedly encourage investment in high-cost regions like the Caspian Basin, price is not the only major factor influencing the speedy development of Caspian oil resources. Rather, a host of complicated economic, logistical and geopolitical obstacles block the region's ability to become a major oil-producing province of the magnitude of the Arab Gulf or even the North Sea or Latin America.[12]

First, Caspian oil resources are located at a great distance from the world's major energy-consuming regions. The countries of that region are landlocked. The region's producers cannot simply ship oil by tanker from domestic ports to international sea-lanes as is done from the Arab Gulf. Instead, Caspian producers must rely on expensive pipelines built through neighbouring countries as the chief means of transport. However, most of the existing and proposed routes suffer from a variety of security issues related to regional political uncertainties and thorny ethnic feuding.

Secondly, the region is also far from major supply centres for exploratory equipment and faces a debilitating shortage of modern drilling platforms and other related supplies. The constraints on infrastructure, drilling equipment and rigs are more severe in the Caspian Basin than probably anywhere else in the world. This means that oil wells take considerably longer to complete, in some cases up to two years as compared to two to three months in other parts of the world.

Such logistical obstacles mean that while its oil resources may be geologically equivalent to the North Sea, the Caspian's output is unlikely to reach that potential. North Sea production has risen from roughly 2 mbd in 1980 to 6 mbd today, or 8% of current world demand. By contrast, after two decades of development and an investment of $13 bn, Caspian oil production may account for no more than 3% to 4% of world demand by 2010.[13]

Incremental production from the Caspian Basin can, at the margin, contribute to a weakening of oil price levels. It is estimated that without Caspian oil supplies, nominal oil prices in 2010 could be as much as $5/b higher than otherwise. But with Caspian oil, oil prices could be lower in 2010 by an estimated $2/b-$5/b.

This more conservative outlook for Caspian output suggests that Arab producers' market control may remain relatively unaffected by the existence of vast Caspian reserves in the short to medium term. Moreover, Arab Gulf producers can benefit from low oil prices to the extent that such price levels contribute to a rise in oil use, creating an opportunity for sustainable market share expansion and giving investors extra incentive to channel exploration capital into low-cost areas such as the Arab Gulf.

An exportable Caspian oil surplus of the order of 2.3 mbd by 2010 could end up flowing towards the European market. It is quite plausible that these barrels will replace some Arab Gulf barrels. This will occur just as Latin American production meets more and more of North America's growth in import demand. The result will be that Caspian and Latin American output will meet much of the growth in the Atlantic Basin's crude oil imports. This could redraw the crude trade patterns, pushing Gulf oil supplies increasingly away from the Atlantic Basin towards the Asia-Pacific region.

Implications for Energy Security

During the Cold War, the issue of energy security was clear-cut. Western nations did not want the Soviet Union to gain an advantage over the resources of the Arab Gulf. The primary threat to the flow of oil was Soviet control.

A lot has changed since then. The Cold War is over and the perception that the FSU could control oil flows from the Gulf is gone. The focus has instead shifted to the possibility of oil supply disruptions resulting from conflict in the Middle East.

Another development shaping the issue of energy security has been the proliferation of oil-producing countries. Between 1978 and 1996, 22 new non-OPEC countries began producing oil, an increase of more than 40%. This is due, in part, to the break-up of the FSU, but it also includes new producing countries in Africa and Asia.

With these changes over the last 15 years, the issue of energy security has become less clear-cut. Even though net importing countries are and will remain dependent on oil from the Arab Gulf, the magnitude of the threat seems smaller.

However, concern over energy security will never go away, but each new supplier contributes to the perception of a diminishing threat. In this case, the Caspian does enhance energy security by providing a volume of oil that is not unimportant as an alternative source. But assuming that pipeline projects go forward, Caspian oil will add to non-OPEC oil supplies and will postpone the time when OPEC supply once again surpasses non-OPEC supply (projected to be around 2020).

The Great Game

At its simplest level, the Great Game is about who owns the Caspian oil reserves and who controls the pipelines that carry the oil to the global markets.

With billions of dollars and crucial strategic influence at stake, the struggle for control over the vast oil resources in the Caspian Basin is a tale of political intrigue, fierce commercial competition, geo-strategic rivalries, ethnic feuding and elusive independence. Some analysts have compared this situation to the "Great Game" – a nineteenth-century rivalry between Victorian England and Tsarist Russia for the control of the region.

It is too early to declare the game over. But after years of inconclusive wrangling, the 21st century Great Game is starting to yield clear national and corporate winners.

Among companies, British Petroleum, ENI of Italy and (above all) ChevronTexaco of the United States appear to hold claim to the bulk of regional reserves, as well as crucial pipeline routes. Among countries, the clear winner is Kazakhstan, which is now believed to hold up to 75% of all Caspian reserves.[14]

The United States can also celebrate a strategic victory: it is now close to achieving its goal of ending the old Russian monopoly on Caspian export pipelines.The centerpiece of U.S. policy has been to promote the Baku-Tbilisi-Ceyhan (BTC) pipeline. Despite lingering doubts about the safety of the war-torn route, financing and the size of Azerbaijan oil reserves, construction on the $3 bn project is set to begin in June this year. Oil is slated to flow by early 2005.

At the same time, President Putin of Russia appears to be plotting a Russian comeback. He has been travelling around the Caspian, laying the groundwork for a regional supply cartel, a kind of mini-OPEC led from Moscow. The potential is there: the key to a cartel is production capacity. Under plans now in the works, the Caspian region (including Russia) could be exporting 7 mbd by 2012, almost equivalent to the current exports of OPEC's giant Saudi Arabia. It is not inconceivable that Putin will one day convince Russia's former satellites that together they can move markets to their own advantage.[15]

In the final analysis, the actual winner of the Great Caspian Game is the one who is in the strongest negotiating position. The United States and western oil companies seem to be in that lucky situation.

Conclusions

With ultimate reserves of 40 to 60 bb, the Caspian Basin does not pose a major challenge to the supremacy of the Arab Gulf as a pivotal supplier of oil to world markets. Apart from the limited size of the reserves, Caspian oil is very costly to find, develop, produce and transport to world markets.

With a long-term production potential that would contribute roughly 3% to future global oil supply, the Caspian will never be a strategic alternative to the Arab Gulf. Still, the Caspian is destined to play a supporting role rather than a deciding one in supplying the world oil market in the future.

Today a fully built-up cost for the Caspian barrel of oil is roughly $12-$15/b. This compares well with the North Sea but it is still some three to four times more than the equivalent barrel in the Middle East. Progress in Caspian oil development is still heavily dependent on a sustainable $20/b (real) oil price and above. What happens to the price of oil will be crucial in determining the size of Caspian oil and its contribution to world oil supplies.

Incremental production from the Caspian can at the margin contribute to a weakening of oil price levels. However, at 3% of world oil supply by 2010, it will not be a significant threat to the market control and market share of the Arab Gulf.

Footnotes

[1] Fadhil J. Chalabi, Gulf Oil vs. the Oil of the Caspian Sea (a paper published by the Emirates Center for Strategic Studies & Research (ECSSR), Dhabi, UAE ,2000), p. 155.

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Modeling the Economic Impacts of Offshore Activities in the Alaska Arctic

*By Jonathan Skolnik and Chris D. Holleyman**

Abstract

Production of oil and gas in the offshore Alaskan Arctic relies upon a set of technologies unlike those used anywhere else in the world. Remote locations, temperatures of 60 degrees below zero, and shifting ice flows that rule out traditional platforms, waterborne craft and sea-floor pipelines are just a few of the challenges that must be overcome. The solutions include roads and islands built of ice, man-made gravel islands, pipelines buried below the ocean floor, and cold weather retrofitted vehicles and equipment that are run for years without ever being turned-off.

Economic impact modeling of these activities also requires a set of methods that are unique. Readily available regional economic impact models contain production functions that are based on national averages. These national-level input coefficients cannot accurately reflect the unique arctic production function. These models are also unable to accurately trace the regional distribution of purchases made by the industry or the workers who commute to the site. Finally, these readily available models do not have enough detail to accurately model the differing impact of specific projects.

This paper describes the development of a first step model that can be combined with a readily available regional model to produce more accurate estimates of economic impacts. The first step model utilizes vectors of purchases, disaggregated by both geographic area and activity, to allow a more accurate accounting of the inputs required for a specific project. The vectors are constructed by coding detailed engineering estimates of inputs to the individual activities. These direct inputs can then be used to stimulate the standard regional impact models.

Introduction

The Outer Continental Shelf Lands Act, as amended, established a policy for the management of oil and natural gas in the Outer Continental Shelf (OCS) and for protection of the marine and coastal environments. The Act authorizes the conduct of studies in areas or regions to determine the "environmental impacts on the marine and coastal environments of the OCS and the coastal areas which may be affected by oil and gas development." The U.S. Minerals Management Service (MMS) is the administrative agency responsible for leasing submerged Federal lands.

The National Environmental Policy Act (NEPA) of 1969 requires use of the natural and social sciences in any planning and decision making that may have an effect on the human environment. To this end, the MMS prepares Environment Impact Statements (EIS) and environmental assessments (EA); acquires marine environmental data; analyzes data, literature surveys, socioeconomic studies, and special studies; and holds public conferences. These undertakings often call for assessing the regional economic impacts of a proposal such as a lease or a sale.

In the past, an assortment of models and methods were used to estimate economic impacts, and these typically varied by planning areas. At present, the existing models used to develop direct OCS and secondary employment projections for the Alaska OCS Region are outdated and do not produce results comparable to other OCS regions such as the Gulf of Mexico. As a result, regional comparisons are difficult to make. Section 18 of the OCS Lands Act, however, requires that the U.S. Department of the Interior prepare a 5-year schedule of lease sales that considers "an equitable sharing of developmental benefits and environmental risks among the various regions." For this reason, MMS decided to standardize the approach used to estimate regional economic impacts and has settled on IMPLAN, an economic input-output model, for that purpose.

To facilitate EIS work for Alaska's OCS Arctic subregion and to develop a tool for the "equitable sharing" analysis, a new model was developed. It can estimate industry employment and expenditures, by region, of offshore oil exploration and development (E&D) activities in the Beaufort Sea. The new model is known as the Arctic Impact Model for Petroleum in Alaska (Arctic IMPAK). Unlike the current model, this new model is designed to produce a set of outputs that can be used to stimulate IMPLAN.

The Current Modeling Process

Economic analysis of lease sales in all areas begins with the Exploration and Development (E&D) Scenarios. The first step model refers to any model that translates the E&D Scenario into direct effects. Direct effects are defined as those resulting from the first round of spending by companies working directly on an OCS project(s). The first-step model must estimate the level of industry expenditure (or employment) and how that spending/employment is allocated to onshore geographic areas. The MMS calls the spending allocation to industry a "cost function."

For Alaska, the previous first-step model was the Manpower model. It simply converted OCS activities levels from the E&D scenarios (number of wells drilled, platforms installed, pipeline miles laid, etc.) into estimates of direct employment using ratios, such as employees per mile of pipelines laid. It was developed in the late 1970s and then refined in the early 1980s. No documentation of the model or the sources of the underlying estimates is available.

The second-step model is used to estimate the additional impacts that result as the initial spending reverberates throughout the economy. These secondary impacts are often referred to as indirect and induced effects. Such models must be developed specifically for OCS or must be customized to reflect the unique expenditure and commuting patterns of OCS-related companies and their employees. For Alaska, these problems are exacerbated by the fact that national models like IMPLAN often use national multipliers due to inadequate local data. In order to use IMPLAN as a second step model, the first step model must provide extremely detailed results.

For Alaska, the second-step model that was used in conjunction with Manpower was the Rural Alaska Model (RAM), which was developed by the University of Alaska Anchorage. Like Manpower, RAM is a set of spreadsheets that

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uses simple multipliers to estimate results. This model can be used to estimate impacts only at the local level and does not allow for the estimation of impacts at the state or national level.

Purpose and Objective

The purpose of this paper is to describe the development of a model to replace the Manpower Model. Since the early 1980s, when the Manpower model was constructed, there have been significant technological changes in offshore E&D activities. In addition, the production process used in Alaska's arctic regions differs significantly from the process used in the sub-Arctic regions that were modeled in the Manpower model.

In developing the new model, the latest available data were used to develop employment and expenditure factors for the revised E&D activities. With these updated factors, projections of direct and indirect employment impacts in the sub-Arctic region can be forecast more accurately. With more accurate projections, stakeholders will have more confidence in the economic sections of an EIS. More accurate projections may also be used in decisions regarding post-lease mitigation.

The new first-step model converts E&D inputs into direct employment and expenditure impacts for the North Slope Borough (NSB), the state of Alaska, and the rest of the United States. The NSB is the local government for the land area to the south of the Arctic OCS. Shore-based OCS activity would be located in the NSB. Expenditure impacts are itemized by IMPLAN sector. MMS can use the model to estimate the direct impacts of an E&D scenario then enter these impacts into IMPLAN to estimate the indirect and induced effects. Cost functions are used to customize the inputs for IMPLAN. MMS has selected IMPLAN to forecast secondary economic impacts because it is a national level model that will standardize comparison with other MMS OCS regions.

Organization

The economic impact of a particular set of oil and gas activities on the Arctic OCS will depend on both the size of the project and the set of technologies chosen. In the next section of this paper, alternate technologies are first defined and then the most likely set of technologies is chosen.

In the following section, these choices are then compared with the categorization of activities contained in the E&D scenario to assess compatibility. Based on this comparison, the final set of activities is chosen for inclusion in the model. The activities are then defined as either primary or secondary activities. Primary activities include those activities whose levels are determined directly from the E&D scenario. In contrast, secondary or support activities (hotel/camps, personnel transport, ice roads, helicopter support and barge support) are those whose levels are dependent on the levels of several primary activities.

Finally for the chosen set of nineteen activities, a basic unit of activity (mile of pipeline, day of helicopter support, barrel of oil, etc.) is determined.

The next section provides an overview of the methods used to develop the inputs to the nineteen activities that comprise the oil exploration, development and production process in the Alaskan Beaufort Sea. In some sense, this study develops a production function for each activity, where the production function is defined in terms of expenditures for various types of inputs. These inputs can be broadly grouped into the following categories: labor, capital, materials, purchased services and government.

The final section of this paper provides an overview of the inputs and outputs of the completed IMPAK model.

Selection of Technologies

The economic impact of a particular set of oil and gas activities on the North Slope will depend on both the size of the project and the set of technologies chosen. In this section alternate technologies are defined and described and the most reasonable and likely set of technologies is chosen.

Table 1 provides a listing of the technical options for oil and gas activities in the Alaskan Beaufort Sea. This table was developed by combining a variety of tables and materials from the Draft Beaufort Sea/Northstar EIS, supplemented by interviews conducted for this study. For each major activity, the table defines the alternate technologies, their characteristics, advantages and disadvantages. The technologies that were chosen for use in this study are highlighted in bold print.

The analysis clearly indicates that there are a large number of potential technological alternatives. For example, approximately fifteen potential drilling structures were identified. Given the complexity of modeling the technologies, it is crucial to select the most likely technologies and to concentrate on modeling the production functions and the economic impacts of those technologies.

The following is a summary listing of the chosen technologies:

- Drilling Method - Directional
- Seismic Surveys - From Ice
- Exploration Structures - Ice Islands
- Development Production Structures - Manmade Gravel Islands
- Oil and Gas Recovery - Gas Cycling
- Oil Processing - Full Offshore Processing
- Product Transportation - Pipeline Buried Beneath Seafloor
- Abandonment - In Place

In each case only a single technology was chosen. For exploration both ice islands and Sinkable Island Drill Ships were considered economical and environmentally friendly options. However, ice islands are the more utilized and proven technology. The estimation of alternative data for seismic surveys on ice and by boat were also considered, but given the relatively small size of this activity it was not deemed worthwhile to do so. While it was recognized that both methods of conducting seismic surveys are likely, the economic differences are not significant. Gravel islands, full offshore processing and pipeline transports were clearly superior both technologically and environmentally when compared with other current options. However, as exploration moves to deeper water, the use of alternative production structures will become more likely. As water depths increase, the cost of gravel islands increases more than proportionately. At 75 to 100 feet these costs probably become prohibitively expensive.

E&D Scenarios, Secondary Activities and Units

Since the level and timing of activities must be derived from the E&D scenario, the level of each activity must be defined in terms of the E&D scenario. Table 2 provides an

Table 1: Technical Options for Oil and Gas Activities in the Arctic OCS		
Phase	**Activities**	**Reason For Consideration or Elimination**
Drilling Methods	• **Directional Drilling Technology**	• *Can access multiple bottom hole locations for single surface location.*
	• • *Vertical Drilling Technology*	• *Only accesses reservoir directly beneath drilling location.* • *Multiple drilling locations increases costs and environmental impacts.*
Seismic Surveys	• *From Boat*	• *Summer Only*
	• • **From Ice**	• *Winter Only* • *Lower environmental impact*
Drilling Structures	• *Onshore Drilling*	• *Too far from reservoir.*
	• *Barrier Islands*	• *Environmental value is too high.*
	• *Bottom-founded Structures* - Caisson Retained Island (CRI) Designs and Tarsiut Island (Concrete CRI)	• *Relocation difficult as caissons ballasted with sand.* • *Redesign and construction of a new caisson structure would be very expensive.* • *Owners proposed to modify to accommodate production facilities (22-35 wells).*
	- Concrete Island Drilling Structure (CIDS)	• *Designed for arctic in water depths of 35 to 55 ft (10.6 to 16.8 m).* • *Demonstrated long-term durability.* • *High cost to convert to production facility.*
	- Mobile Arctic Caisson (Molikpaq)	• *Owners proposed to modify to accommodate production facilities (40 wells).* • *Designed for arctic in water depths of 30 to 130 ft (9 to 39.6 m).* • *Demonstrated durability.* • *High cost to convert to production facility.*
	- Single Steel Drilling Caisson (SSDC)	• *Owners proposed to modify to accommodate production facilities (30-40 wells).* • *Can operate in arctic in water depths of 25 to 100 ft (7.6 to 30 m).* • *Demonstrated durability.* • *High cost to convert to production facility.*
	- **Manmade Gravel Islands**	• *Proven technology, 17 constructed in Beaufort Sea.* • *Useful to approximately 50 ft (15.2 m) water depth.* • *Can withstand high lateral load ice forces.* • *Less expensive to design, construct, and maintain than other structures.*
	- Seafloor Templates	• *Usable in water depths over 200 ft (61 m) where ice gouging does not occur.* • *Water depth too shallow.*
	- Sub-sea Silos	• *Unproven in Beaufort Sea but conceptual design addresses potential hazards.* • *Caisson-protected subsea templates have been used in arctic* • *High cost.*
	• *Floating Structures* - Jack-up Drilling Platforms	• *Not designed to operate in ice or support production.* • *Could support summer exploration.*
	- Semi-Submersible Drilling Vessels	• *Not designed to operate in ice or support production.* • *Could support summer exploration.*
	- Conventional Drill Ships	• *Not designed to operate in ice or support production.* • *Could support summer exploration.*
	- Conical Drilling Unit (Kulluk)	• *Not designed to operate in ice or support production.*
	- **Ice Islands**	• *Melt in summer but low environmental impact and cost.* • *Supports winter exploration.*
	• *Sub-sea Cavern*	• *Unproven concept not yet demonstrated as technically or economically feasible.*
	• *Sinkable Island Drill Ship (SIDS)*	• *Demonstrated technology.* • *Useful to only approximately 50 ft.* • *Suffers occasional ice damage* • *Can be used year round.* • *Extremely low environmental impact and cost* • *Relatively easy to relocate*
Oil and Gas Recovery	• *Natural Blowdown (Primary Recovery)*	• *Recovery rates of 5% to 20% are not economic.* • *Usable on large reservoirs with difficulties implementing pressure enhancement.*
	• *Secondary Recovery*	• *Effective if the reservoir contains heavy, thick oil or has high water content.* • *Not appropriate because of composition of Northstar reservoir.*

Table 1 continued next page

Table 1: Technical Options for Oil and Gas Activities in the Arctic OCS		
Phase	**Activities**	**Reason For Consideration or Elimination**
Oil and Gas Recovery	• *Natural Blowdown (Primary Recovery)*	• *Recovery rates of 5% to 20% are not economic.* • *Usable on large reservoirs with difficulties implementing pressure enhancement.*
	• *Secondary Recovery* - Gas Lift	• *Effective if the reservoir contains heavy, thick oil or has high water content.* • *Not appropriate because of composition of Northstar reservoir.* • *Gas supply available in the Alaskan Beaufort Sea.* • *Can be integrated with other recovery methods.*
	- **Gas Cycling**	• *Highest recovery rates of 45% to 65%.* • *Can be integrated with other recovery methods.* • *Useful for light oils that flow easily.*
	- Water Injection	• *Recovery rates of 35% to 45% are not economical.* • *Can be integrated with other recovery methods.*
	- Waterflood	• *Recovery rates of 40% to 50%.* • *Can be integrated with other recovery methods* • *Best backup method.*
	• *Enhanced (Tertiary) Recovery*	• *Not considered because options are unknown.*
Oil Processing	• **Full Offshore Processing**	• *Secondary oil recovery techniques can be incorporated.* • *Transport sales quality oil directly from production facility.* • *Lowest environmental impact.*
	• *Partial Offshore and Onshore Processing*	• *Difficult transportation of three-phase fluids by pipeline.* • *Multiple locations increases environmental impact.*
	• *Full Onshore Processing*	• *Offshore production structures can be smaller.* • *Difficult transportation of three-phase fluids by pipeline.* • *Environmental impacts too high onshore.*
Product Transportation	• *Tankers and Barges*	• *Greater spill risk.* • *High cost for facilities and dredging.*
	• *Pipeline on a Gravel Causeway*	• *Provides protection of pipeline and access for maintenance.* • *Negative environmental impacts* • *High cost for bridges.*
	• **Pipeline Buried Beneath Seafloor**	• *Avoids damaging effects from ice.* • *Safest option with lowest impact*
	• *Pipeline Installed on Seafloor*	• *Risk of damage or rupture from ice.* • *Can be used only in water depths over 200 ft (61 m).*
	• *Elevated Pile-supported Structure*	• *Would be exposed to winds, wave action, and ice forces.* • *Structure could impede passage of vessels/barges.*
Spoil Disposal	• *Onshore*	• *Saline material kills terrestrial vegetation.*
	• *Shallow water*	• *Sediments block water circulation and navigation.*
	• ***Outside Barrier Islands***	• *Achieves good dispersion of waste material.* • *Does not impede water circulation or navigation.*
Abandonment	• **In Place**	• *Preserves key facilities for reuse and shelter.*
	• *Removal*	• *Returns environment closer to original state.*

Notes: ft = Foot or Feet
Km = Kilometer(s)
m = Meter(s)
% = Percent
TAPS= Trans Alaska Pipeline System

example of the format and content of an E&D scenario for arctic Alaska. The types of activities included in the E&D scenarios and their definitions were an important consideration in developing the activities to be included in the IMPAK model.

In addition, while the E&D scenario only specifies a relatively few activities, many of these E&D activities share common support type activities. These include ice road construction, spoils disposal, headquarters support, personnel transport, helicopter and barge support and camp support (room and board). Since the labor, material and equipment inputs to these secondary or support activities are similar across the more primary activities, it is advantageous to separate these components from the primary activities and have the levels of these activities depend on the levels of the primary activities.

Table 3 provides a listing of what were considered primary activities. Fourteen activities are listed in roughly chronological order. Note that the construction and operation of facilities are separated, as operation often continues several years. Also included in Table 3 is a listing of the secondary or support activities. Five of these activities have

Table 2: Example of an E&D Scenario for Arctic Alaska

Year	Exploration Wells	Delineation Wells	Exploration/ Delineation Rigs	Production Platforms	Production and Service Wells	Production Rigs	Landbase Operations	Oil Production	Pipeline Miles
1998	Lease Sale								
1999	1		1						
2000	1	2	2						
2001	1		1						
2002	1	2	2						
2003	1		1				0.1		
2004	1	2	2	1	4	1	0.2		
2005					10	2	0.2		15
2006				1	18	3	0.2	9	10
2997					16	2		13	5
2008				1	18	3	0.1	18	
2009					16	2		26	10
2010					5	1	0.1	31	
2011								39	
2012								35	
2013								32	
2014								27	
2015 . :								23 . :	

been identified including:

- North Slope Support
- General Personnel Transport
- Ice Roads
- Helicopter support
- Barge support

It was important to rigorously define each activity to insure that there was no double counting. It was also important to ascertain the extent to which the secondary activity varies depending on the primary activity it is associated with. For example, there are differences in the thickness and width of ice roads used during different activities.

The primary and secondary activities are structured so that if a primary activity occurs, predetermined amounts of the required secondary activities are stimulated. For example, if a production island is in operation, a certain amount of helicopter support flights will occur. The number of helicopter flights will vary based on certain aspects of the scenario, such as the distance of the project from shore and the number of islands in operation.

In order to model the impacts of a particular oil and gas development it is necessary to have estimates of the size of the development. These estimates, as provided in the E&D scenario reproduced in Table 2, define the development in terms of number of wells, miles or kilometers of pipelines, etc.

Finally, activities must be defined in terms of a unit of time or size. Table 3 provides a unit for each of the activities

Table 3: Primary and Secondary Activities - Drivers and Default Factors

Primary Activities		Secondary Activities				
		15. North Slope Support	**16. General Personnel Transport**	**17. Ice Roads**	**18. Helicopter Support**	**19. Barge Support**
	Units	Per 300 Person Camp Per Year	Per Day	Per 10 Miles	Per Day	Per Day
1. Survey on Ice	Per Month				X	
2. Ice Exploration Island	Per Island	X	X	X	X	
3. Exploration Wells	Per Well	X	X		X	
4. Place Gravel Island	Per Island	X	X	X		
5. Gravel Island Protection	Per Island	X	X	X		X
6. Equip Production Island	Per Island	X	X	X	X	X
7. Production Wells	Per Well		X		X	
8. Operate Production Island	Per Island Per Year	X	X	X	X	X
9. Construct Offshore Pipeline	Per Ten Miles	X	X	X	X	
10. Construct Onshore Pipeline	Per Ten Miles	X	X	X	X	
11. Landbase Operations	Per Year	X				
12. Well Workover	Per Well Per Workover	X	X		X	X
13. Spill Contingency	Per Year Per Ten Islands	X	X		X	X
14. Abandonment in Place	Per Island	X	X		X	X

used in the IMPAK model. These units were designed to be as compatible as possible with the E&D scenarios. At the same time they needed to match with the engineering and cost data that were collected for the study.

Data Development Methodology

In some sense, this study is developing a production function for each activity, where the production function is defined in terms of expenditures for various types of inputs. These inputs can be broadly grouped into the following categories: labor, capital, materials, purchased services and government.

The estimates developed in this study were based on information collected in the years 1999 and 2000 and published reports providing data for various years, but mostly for the years 1997 to 1999. As such, the authors consider the estimates provided in this paper to be reported in 1999 dollars.

Labor Inputs

Labor inputs include the direct labor used in the construction and operation of the oil and gas facilities as well the overhead or headquarter salaried non-production staff that provide support functions over a range of operations. The direct construction labor inputs were estimated through interviews with representatives of construction contractors and oil companies that have experience in constructing or operating the structures under consideration. In most cases, data were collected, by activity, on the number of employees by trade, wages for employees by trade, task crew size, duration of task, number of shifts, shift duration, rotation pattern and percent native hire. The numbers of headquarters and support staff were estimated based on published Census data on the ratio of total workers to production workers. Non-production employment within Alaska was then divided between the NSB and the remainder of Alaska based on data provided by industry sources. Wages for salaried employees were estimated separately for the various geographical regions based on the State of Alaska's Employment and Earnings Summary Report except for U.S. wages which were based on data from the 1997 Census of Mineral Industries. Wages for all workers in all geographic areas were then adjusted to include an estimate of the value of fringe benefits based on Census data.

In calculating estimates of economic impact in cases where workers are commuting, it is necessary to consider both where the employees work and where they spend their disposable income. Therefore, while data were initially developed based on the location of the workplace of the individual, these estimates were then converted to estimates of the location in which the expenditures of wages and taxes are made. Once employees are paid wages, they will pay taxes, save a small part of these wages and then spend the rest on goods and services, generating induced impacts.

Where an employee spends his/her income depends, to a large extent, on whether the employee is a resident of the NSB. Since food, lodging and transportation are part of an employee's total compensation package, it is unlikely that non-residents spend much of their disposable income in the NSB. Study team members with experience working in the area, estimated that workers in the NSB spent approximately $5 per day at informal lobby shops or on local crafts. Since most employees make in the range of $500 per day, it was assumed that one percent of disposable income is spent on NSB goods. Full time NSB residents, on the other hand, are inclined to spend relatively more of their disposable income in the NSB. Those natives who still live in the NSB, estimated at 25 percent of all natives, were estimated to spend the majority (80 percent) of their income there, with the remainder spent on the occasional trip to Anchorage or other destinations. NSB natives who had left their native village were estimated to spend none of their disposable income in the NSB, other than the one-percent spent while working. In addition, it was assumed that all employees in Alaska spent all of their disposable income within Alaska and that all non-Alaska employees spent all of their income in the rest of the U.S. not including Alaska.

In addition to direct compensation, several contractors provided estimates of additional employee related costs for airfare to and from the NSB, local transportation, clothing, and housing and meal costs. While these costs are theoretically not part of employee compensation, but rather part of overhead costs, their levels are dependent upon the numbers and of employees and are, therefore, most accurately estimated along with employee compensation. They were assumed to not be included in Bureau of the Census estimates of fringe benefits and were coded directly to the appropriate IMPLAN sectors. As described below, they were subtracted from estimates of total overhead prior to distributing remaining overhead expenses to IMPLAN sectors.

Capital Inputs

Unlike most labor and material inputs, which are entirely and immediately consumed in the production process, capital inputs are used up gradually over time. This defining aspect of capital requires special attention when utilizing an input-output (I-O) framework to estimate economic impacts. Capital expenditures are not included in the use coefficients of an industry, which only account for inputs that are immediately consumed for current production. In an I-O model, annualized capital expenditures are included with value added. Unfortunately, these expenses are frequently aggregated and, without a capital flow matrix, it is not possible to isolate specific types of investments or trace the secondary impacts associated with such investments. For this reason, exogenous estimates of capital investment are often developed outside of the I-O model, and then used as model catalysts along with other direct expenditures.

Capital investments represent a substantial portion of mineral exploration and development (E&D) expenditures. Due to the harsh environment, this is especially true in Alaska's Arctic environment, where many of the machines only last four years and are often operated for long periods of time without even being turned off. E&D activities require transportation and earth moving equipment, drilling equipment, etc.

The first step in the process was to identify the capital assets used in each E&D activity. It should be noted that much of the equipment has to be retrofitted with special accessories before it can be used in the harsh conditions found in the Alaskan Arctic. These accessories include insulation, special engine lubricants, and hardware attachments. The accessories associated with each primary piece of capital were also identified in this first step. The numbers of assets required to carry out one unit of the activity were then estimated. This information was compiled through surveys of construction and mining contractors and supplemented with engineering and economic judgment.

The cost for each asset was then annualized (based upon the average life of the machine), converted into a "per unit" basis, and then divided into its various cost components: i.e., manufacturing, transportation and wholesale trade, and retrofitting. Regional purchase coefficients (RPC) were then used to allocate expenditures to impacted geographic regions. This allocation was performed for each cost component. For example, the manufacturing cost of a particular asset may have been assigned to the rest of the United States (not including Alaska) whereas part of the cost of delivering it to the North Slope may have been assigned to the NSB. Finally each cost component was assigned to an associated IMPLAN sector and annual expenditures were summed across assets. RPC is a term which briefly is defined as the percentage of purchases of a particular good or service obtained from within the study area.

Material Inputs

Most major material inputs such as fuel were estimated based on information on cost and quantity gathered in the industry interviews or based on the expert engineering knowledge of project staff. However, in order to determine what materials and purchased services are utilized in quantities that are significant enough to warrant estimation, data from the latest national-level input-output table of the U.S. economy was tabulated and analyzed. In summary, material inputs to the oil and gas production process are made up of four main types of commodities including:

- Chemicals
- Products of petroleum refining such as gasoline as well as lubricating oils and greases
- Various paving and building compounds such as asphalt, concrete and cement
- Specialty minerals used in well drilling operations.

The types of products for each of these sectors and their associated SIC code were a useful input to the interviewing process. Estimates were solicited on the usage of these various inputs for the particular activity under consideration. These estimates were often based on usage rates for particular pieces of equipment that were then multiplied by the number of units in use, the hours or days of use per piece of equipment and the cost per unit of the input. An example would be the gallons of fuel used per day for a pickup truck. The number of pickup trucks and the number of days they were employed in the task would then be multiplied by this estimate. Total usage would then be multiplied by the cost of fuel. Since the products were already defined by SIC code and input-output sector it was a simple matter to code them to IMPLAN sector. As the estimates were in purchasers' prices, rough estimates of shipping costs by mode and wholesale and retail margins (if applicable) had to be made prior to assignment to sectors. Finally, the area of production was specified, so that the resulting values could be divided among the NSB, the remainder of Alaska and the other 49 states.

Purchased Services (Overhead)

The national-level input-output table was also analyzed for purchased services and overhead sectors for which estimates of purchases were not compiled within the labor, capital or materials procedures. These include sectors such as telephone services, banking, insurance, hotels, data processing, advertising, legal, engineering and architectural, accounting, eating and drinking places, and business associations.

The purchases from these sectors, which represent overhead types of services, are usually not separately specified in engineering cost estimates. If they are considered, they are generally lumped together in a common overhead category. Moreover, while these purchases are part of the real costs of doing business they are not easily allocated directly to the different activities that comprise the oil and gas industry. That is to say, they are common overhead components. The amount of advertising that is purchased by a large oil company, for example, is probably fairly independent of the miles of ice roads constructed, but is probably somewhat related to gallons of oil produced. On the other hand, a smaller company specializing in ice road construction, although likely to have a small advertising budget, is also likely to have spending that is fairly related to the miles of roads it constructs in a year.

The assignment of these costs by area is also extremely complicated. The oil and gas industry is an amalgamation of a large number of companies, not just the big oil companies. For example, the 1992 Census of Mineral Industries estimates that almost 17,000 companies were involved in the Crude Petroleum and Natural Gas and Oil and Gas Field Services industries. Therefore, one can not simply ask the large oil companies where they spend their overhead dollar, even assuming they would be willing to provide an answer. Instead, estimates must be made of where the aggregate of all companies makes their expenditures.

As a result, the estimates of spending for each purchased service were based on the following methods. First, estimates of overhead expenses, developed for each activity based on interviews and expert engineering judgments, were allocated to the 18 purchased services sectors based on the relative value of consumption provided in the national-level Bureau of Economic Analysis (BEA) Input-Output (I-O) table. Data for the oil and gas industry were used for all activities except camp support, general transport, and helicopter and barge support. Data for these sectors were based on the BEA I-O data for hotels, local transport, air transport and water transport, respectively. The resulting estimates were then split among the NSB, Alaska and the other 49 states using percentage distributions developed by study staff based on their familiarity with the area and the production process.

Government

The model also calculates government expenditures, which are set equal to government revenues in the prior year. Government revenues were generated from IMPAK outputs for that prior year and a series of local, state and federal tax rates. Revenue sources include taxes on employee earnings, employee spending, Permanent Fund (PF) dividends, 8(g) funds, gravel royalties, oil and gas royalties, lease revenues and bonus bids. Government revenues were distributed to a number of IMPLAN sectors based on separate input-output vectors developed for local, state and federal governments. Each cell in the vectors represents a percentage of the respective total government expenditures. For the most part, it was assumed that all expenditures will take place in the region in which the government is located.

In addition, the model includes data for Trans-Alaska

Pipeline system (TAPS) expenditures, which are assigned to the IMPLAN pipeline sector. It was assumed that TAPS expenditures in a given year are equal to TAPS revenues generated in the previous year. These revenues were estimated by multiplying total oil production by a TAPS surcharge, which is defined in terms of dollars per barrel. The user inputs both variables. It was assumed that all oil produced on the North Slope is transported via TAPS to Valdez.

Model Overview

The Arctic IMPAK model forecasts the input requirements needed to carry out oil exploration and development on Alaska's Arctic OCS. In the previous section, the methods used to develop vectors of commodity and labor input requirements on a per unit basis were described. Multiplying these vectors by projected annual activity levels developed from an E&D scenario generates estimates of the total input requirements for each year in the forecast horizon.

The Arctic IMPAK model is contained in a Microsoft Excel platform and is driven by data from the E&D report, as well as other data, which are manually input into the model. Since the activities listed in the E&D reports are not identical to those used in IMPAK, the model has to convert the E&D data into the corresponding IMPAK activity levels. Table 4 details the conversion of E&D scenarios to IMPAK activity levels.

The model inputs are then transposed into a matrix compatible with the regional input-output matrices. An Excel array function is used to accomplish the task. The transposed input is then multiplied by each region's input-output matrix to yield the total direct impacts by region and IMPLAN sector. Again, an Excel array function is used to accomplish the matrix multiplication. Note that each year in the forecast horizon requires a separate formula.

The final output is a matrix that provides total input requirements by IMPLAN sector separately for each year and geographic area. This output then becomes the input for the Microsoft-Access model developed by the MMS. The MMS model estimates the ripple effects in each corresponding, proximate onshore area.

Table 4: Conversion of E&D Scenarios to IMPAK Activity Levels

Activity	Conversion Procedure
1. Geological Survey	Not currently in E&D report, must be manually entered.
2. Construct Ice Island	Equal to number of exploration and delineation rigs in year from E&D report.
3. Drill Exploration Well	Equal to number of exploration and delineation wells in year from E&D report.
4. Place Gravel Island	Equal to number of production platforms in year from E&D report. User can adjust island size and shape.
5. Protect Gravel Island	Equal to number of production platforms in year from E&D report.
6. Equip Production Island	Equal to number of production platforms in previous year from E&D report.
7. Drill Production Well	Equal to number of production wells in year from E&D report.
8. Operate Production Island	Equal to number of production platforms since inception date from E&D report.
9. Lay Offshore Pipeline	Equal to number of offshore pipeline miles divided by ten in year from E&D report.
10. Lay Onshore Pipeline	Equal to number of onshore pipeline miles divided by ten in year from E&D report.
11. Perform Well Workover	Equal to number of production wells in six-year previous increments from E&D report.
12. Landbase Operations	Equal to percentage of landbase operations in year from E&D report.
13. Spill Contingency Operations	Equal to one-tenth of the number of production platforms since inception date from E&D report.
14. Abandonment	In year after E&D activities cease, equal to number of production platforms since inception date.
15. Construct Ice Roads	Based on pipeline miles from E&D reports with factors for depth and width to support specific activities.
16. Helicopter Support	Based on trip per activity ratios, activity levels and trip per day factor based on user specified distance.
17. Barge Support	Based on trip per activity ratios, activity levels, 60 miles per day and user specified distance.
18. General Personnel Transport	Stimulated based on dollar per activity ratios and activity levels.
19. Camp Support	Stimulated based on dollar per activity ratios and activity levels.

Sobering Realities of Liberalizing Electricity Markets

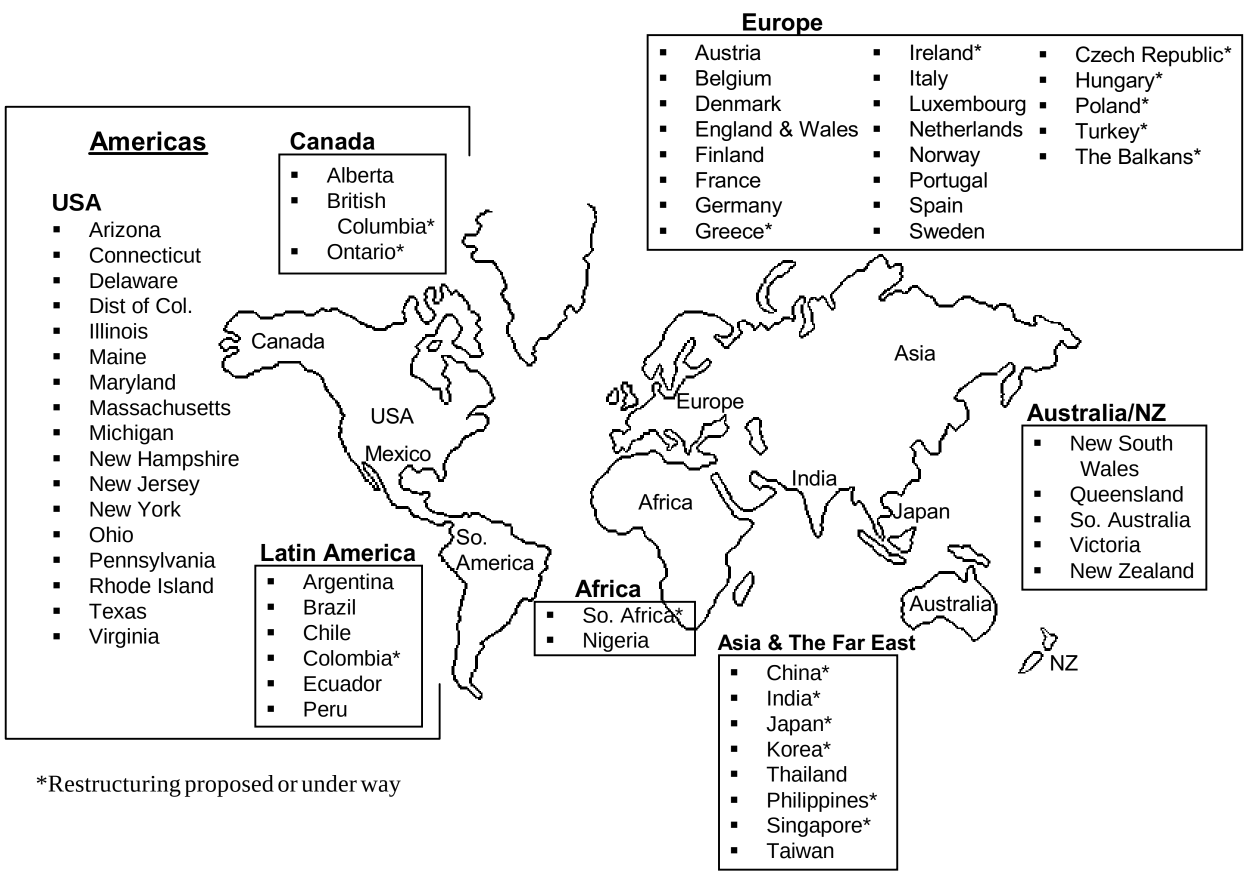
*By Fereidoon P. Sioshansi**

Introduction

England, Wales and Norway are credited with starting a new chapter in electric power sector governance. About the same time, both countries started to liberalize and/or restructure their electricity supply industries (ESI) along different paths. The former two established a centralized, mandatory pool while privatizing a previously government-owned and highly centralized bureaucracy[1]. The latter broadened and formalized what used to be a thriving voluntary bilateral market, while leaving much of the industry in the hands of government-owned or municipal entities[2].

The initial success of these two countries has resulted in restructuring, liberalizing, privatizing, or corporatizing in many parts of the world (Figure 1). For a definition of terms, see the following.

Figure 1
Restructured, Liberalized, Privatized, and Corporatized Markets Around the World



Restructuring, Liberalizing, Privatizing or Corporatizing: What's the difference?

Restructuring: A broad term, referring to attempts to reorganize the roles of market players and/or redefine the rules of the game, but not necessarily deregulate the market. California, for example, restructured its market, deregulated its wholesale market by lifting nearly all restrictions, but kept its retail market fully regulated. Many problems ensued.

Liberalization: Synonymous with restructuring. It refers to attempts to introduce competition in some or all segments of the market, and remove barriers to trade. The European Union, for example, refers to their efforts under this umbrella term.

Privatization: Generally refers to selling government-owned assets to the private sector, as was done in Victoria, Australia, and in England and Wales. It must be noted that one can liberalize the market without necessarily privatizing the industry, as has successfully been done in Norway. The experience in New South Wales, in Australia has been a mixed success.

Corporatization: Generally refers to attempts to make state-owned enterprises (SOEs) look, act, and behave *as if* they were for-profit, private entities. In this case, the SOE is made into a corporation with the government treasury as the single shareholder. For example, former SOEs in New South Wales, Australia, have been corporatized. They vigorously compete with one another, while all belong to the same, single shareholder, namely the Government of

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[1] See footnotes at end of text.

NSW. The Islamic Republic of Iran has been considering such a move for generators.

Deregulation: Essentially a misnomer. No electricity market has been (or, in fact, can be) fully deregulated. Experience suggests that even well functioning competitive markets need a regulator, or as a minimum, a market monitoring and anti-cartel authority. Germany is the only major country attempting to do without a regulator. Even in this case, there is an anti-cartel office, monitoring the behavior of the market participants.

Despite a few setbacks and early disappointments, these efforts have generally been successful and are proceeding in North America and elsewhere[3]. A synopsis of recent developments in the U.S., including the California debacle follows.

Restructuring of U.S. Electric Power Sector Continues Despite Setbacks

What started as a restructuring debate in California in 1994, quickly spread across the U.S. At one point, 24 states had passed legislation to open their electricity markets to competition. But the recent problems in California have cooled the early enthusiasm to liberalize the markets in many states. Consequently, a number of states have postponed their plans to restructure. Currently, 16 states and the District of Columbia may be counted in this camp. The result is an incoherent hodge-podge of competition, not here and not quite there, and in the case of California, re-regulation. According to the Energy Information Administration, the states now fall into the following categories:

Restructuring Active: Arizona, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and, Virginia.

Restructuring Delayed: Arkansas, Montana, Nevada, New Mexico, Oklahoma, Oregon, and West Virginia.

Restructuring Suspended: California.

Restructuring Not Active: Alabama, Alaska, Colorado, Florida, Georgia, Idaho, Hawaii,, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, North Carolina, North Dakota, South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, Wisconsin, and Wyoming.

Source: Energy Information Administration.

Several states —Alabama, Colorado, Idaho, Kentucky, and Louisiana— have studied the issue and have decided that there will be no tangible benefits, at least in the short-run, from restructuring. This conclusion is based on what they can see from developments in other states. Following the well-publicized problems in the California market, a handful of other states have postponed the opening of their markets.

There has not been strong support from consumers. In a number of states, notably Arizona, Michigan, Montana, New Hampshire, New Jersey, Nevada, Pennsylvania, and Vermont, there has been mild to significant opposition to the implementation of the legislation. Policymakers, consumers, regulated utilities, competitive suppliers, and environmental groups have all discovered that there is a dark side to restructured markets:

- Policymakers in a handful of states have decided to delay or postpone the implementation of restructuring for a variety of reasons.
- Consumers and their advocates have discovered that the savings—at least in the short-run—can be non-existent, small, or elusive at best. This is particularly true of states with significant stranded costs, which have to be paid off before meaningful competition can truly start. The scale of stranded costs, once estimated to exceed $300 billion for the U.S., however, has turned out to be significantly smaller. Consumers have also found that prices can be highly volatile and unpredictable, something that many do not like.
- Load serving entities have found that they can be caught short if they have not secured their resource requirements with long-term, fixed-price contracts. A number of LSEs in the West, for example, were badly burned when prices shot up while their retail rates were capped. This has led to the bankruptcy of the nations' largest investor-owned utility, Pacific Gas & Electric Company, as well as financial problems for many others, including Sierra Pacific.
- Competing suppliers have found—surprise—that it costs a lot to acquire customers; it is not easy to hang on to them; it is difficult to sell them additional *value-added services*; and enormously expensive to launch new brands and products. Many have left the business altogether, while others have concentrated exclusively on large commercial and industrial customers, leaving the residential mass market virtually unattended. Green energy has turned out to be a niche market, but even here the going is tough.
- Environmental and advocacy groups have found that in the competitive environment nobody will look after the social goods (e.g., the environment, R&D, energy efficiency, renewable energy, low-income customer assistance, etc.).This means that new mechanisms for funding and implementing such services must be found.

But the glass is not just half empty. Competitive pressures have unleashed enormous forces to reduce costs, improve operational efficiencies, enhance customer services, and offer a host of new products and services. Moreover, a number of new players have entered the previously closed electric power sector. The most notable among these are power marketers and traders (see Table 1) who can increasingly take advantage of federal and state legislation to operate in competitive wholesale markets. While there were a handful of such companies as recently as 1992, at the end of 1999, there were 566. The collapse of Enron and subsequent consolidation has reduced the number, but trading and risk management are now considered as permanent features of the electric power business.

Despite frequent complaints about the *unfair* nature of competition in retail markets in many jurisdictions, customers are beginning to make choices. The turnover rates are not impressive, so far, particularly in the residential sector. In California's failed market, retail competition was suspended in September 2001. Texas, which opened its retail market in January 2002, is expected to have a thriving market – but the jury is still out on this.

Motivations to Liberalize Markets Vary

Although the motivations to restructure were, and continue to be, vastly different in various parts of the world, they

Table 1
Top North American Power Marketers
Ranked by 2001 volume of trade as reported

Company	Volume (MMwh)	Change	Company	Volume (Bcf/d)	Change
American Electric Power	576.0	48.2	Mirant	13.3	92.8%
Reliant Energy	380.4	88.4	BP Energy	12.6	50.0
Mirant	343.4	87.7	Duke Energy North American Wholesale Energy	12.4	4.2
Duke Energy North American Wholesale Energy	335.3	21.8	Reliant Energy	12.2	37.1
Dynegy Wholesale Energy Network	317.0	130.0	Aguila Inc.	12.0	14.3
Williams Energy Marketing and Trading	306.3	133.6	Dynegy Wholesale Energy Network	11.3	16.5
Aquila Inc.	301.1	61.3	American Electric Power	10.6	178.9
El Paso	221.1	86.3	Sempra Energy	10.5	18.0
Constellation Power Source	173.0	8.1	Coral Energy	9.2	-9.8
Entergy-Koch Trading LP	109.0	-7.0	El Paso	9.2	17.9
			Conoco Inc.	7.1	-5.3

Enron and PG&E's numbers were not available for 2001, and these companies are *not* ranked in the above table.
Source: *Energy Markets*, March 2002

generally fall into two broad categories (see Table 2). In developed countries, the industry is mature, infrastructure is already in place, and growth rates are modest at best. In these countries, the prime motivation is to make the industry more efficient by introducing competition and customer choice. Local and regional price disparities are typically among the reasons for large industrial users to push for competition. Another objective is to transfer risks of investment to the private sector, which in developed countries is well developed and fully capable to assume such risks.

Table 2
Different Strokes for Different Folks
Main motivations for restructuring the ESI vary among developed and developing countries

In Developed Countries

Customer choice
Make industry more efficient
Improve operational efficiencies
Better cost management
Investment risks borne by private sector
Remove/reduce price disparities

In Developing Countries

Attract infrastructure investment
Reduce government bureaucracy
Decentralize planning
Reduce/remove price subsidies
Support private sector growth
Keep up with growing demand

In developing countries, the industry usually needs massive infusions of investment in infrastructure to meet growing demand. Governments are often unable to meet the insatiable demand for investments. The prime motivation in these cases is to attract private investment – domestic and foreign – into the sector, and to cut down on bureaucratic red tape and the inefficiencies of centralized, government-controlled planning. In many developing countries, electricity prices are kept artificially low, which further discourages additional investment in the power sector. Privatization is one way to remove price subsidies. There are a multitude of other factors, varying from one country to another.

Regardless of the motivations, during the 90s, it was naively assumed that:

- ESI restructuring is a relatively straightforward process;
- many benefits (e.g., higher operating efficiencies) would *automatically* flow from the introduction of competition and would naturally lead to lower retail prices; and
- the newly liberalized markets would essentially self-regulate themselves, operating as a plane flies on auto-pilot once the coordinates of the destination are specified.

The experience of the markets to date, however, suggests otherwise[4].

Restructured Markets not as Advertised

Recent well-publicized problems with dysfunctional markets[5] such as the one in California have clearly demonstrated that:

- the power market is highly complex;
- many of the assumed benefits of restructuring (e.g., higher operating efficiencies) will *not* occur automatically, nor necessarily accrue to the expected beneficiaries (e.g., lower retail prices for small consumers); and
- even well-functioning competitive markets require constant and diligent monitoring, and a powerful, independent regulator.

As it turns out, California is not alone in experiencing major problems with its electricity market liberalization experiment. The province of Alberta, Canada started on a similar path beginning in 1995 and opened its market to full competition on January 1, 2000. Alberta's problems, while trivial compared to California, nevertheless, demonstrate the potential pitfalls of restructuring. Demand in the province grew by 16% between 1996 and 2000, but supplies did not keep up. What new capacity has come online uses natural gas. More importantly, even though some 70% of the province's energy is generated from low-cost coal plants, the market clearing prices on the Power Pool of Alberta are increasingly set by the much higher cost natural gas plants.

This, coupled with abnormally high natural gas prices in 2000, led to price spikes in the wholesale market during the early stages of the liberalized market. Since every generator gets paid the price set by the last plant at the margin, average pool prices increased to unprecedented levels. Critics charge that the government failed to spell out the details of how the power market would transition to competition, thus discouraging early investments in additional coal-fired capacity.

High prices began to moderate in 2001, falling to around CAN$30/MWh (approximately $20/MWh) by end of 2001. Moreover, high prices have attracted additional investments, which have resulted in lower prices. The Alberta experience suggests that unexpected and unintended things can happen, and it may take months to stabilize prices and/or to restore investors' confidence in the market.

Far to the south of both Alberta and California, Brazil has also had a difficult time with its power markets. But unlike Alberta and California, this one can be mostly blamed on nature. The worst drought to hit the country in 70 years significantly reduced the output of hydroelectric energy, which normally accounts for 90% of the country's needs. As in the case of California and Alberta, uncertainties about market rules and market prices resulted in little or no investment in additional thermal capacity.

In 2001, the government ordered Brazilians to cut down electricity usage starting in June by 20% to avert widespread blackouts. Rationing, which lasted 6 months, affected all consumers. Residential users were asked to cut back usage by 20% or face surcharges as high as 200%. Small consumers who could cut down their usage by 1/3 were exempted from paying any bills. Large industrials were to cut down usage between 15-25%. Violators were fined, or had their power cut off. The situation has improved since these draconian measures were introduced.

As the preceding examples illustrate, there is now a new maturity of expectations in at least three areas:

- **Complexity** – Every one recognizes the enormous complexities of the electricity markets[6].
- **Benefits** – While the introduction of competition unleashes powerful forces to improve operating efficiencies and reduce costs, the benefits do *not* automatically flow to the expected beneficiaries. For example, a disproportionate percentage of the significant cost savings resulting from the initial liberalization and privatization of the ESI in England and Wales allegedly went to the investors – not the customers.
- **Vigilant regulator** – Despite initial beliefs to the contrary, the necessity and the workload of regulators have usually *increased* following the introduction of competition in many jurisdictions. Germany, the only major liberalized market in the world which does *not* currently have a regulator, sorely needs one.

Does Competition *Inevitably* Lead to Lower Prices?

The popular belief used to be that competition will *inevitably*—and *automatically*—lead to lower electricity prices. The reality is never that simple. True, competition *generally* leads to improved efficiencies in operations (e.g., in power generation), cost reductions in certain functions, the introduction of new—and sometimes improved—services. But its impact on retail electricity prices is more complicated for several reasons:

- **Large vs. small customers**. The intense pressures to cater to large and strategically important customers tends to lead to lower prices and/or customized services at little or no cost. Conversely, many small and marginally profitable customers may experience little or no price reductions, end up paying higher prices, and/or suffer service quality degradations. It makes perfect business sense to look after the big customers. That may be the reality of competitive markets. Large customers with their high load factors and high-voltage service levels are cheap to serve. They can also use their high volume to negotiate better deals. Not true for small customers.
- **Profitable customers**. United Airlines estimates that a mere 9% of its customers, the frequent business flyers, account for 40% of the company's profits. Similar numbers apply to the electric power business with the implication that a lot of time and effort will go to cater to these customers, and not much on the others. This was not necessarily the case under regulation.
- **Cost attribution and price rationalization**. Another factor further complicating a meaningful comparison of *pre-* and *post-*competition prices is the disappearance of many subsidies among and across customer classes. Cost allocation and price adjustments, which are highly important and necessary by-products of industry restructuring, tend to result in significant cost shifting among customer classes. Consequently, some prices rise while others decline even in the absence of any net cost reductions.
- **Risk and return.** The introduction of competition to monopoly functions (e.g., power generation and competitive energy supply) introduces certain risks not previously present. This, in turn, requires higher returns on investment to attract and retain capital. The higher risk premium may partially—or totally—offset the gains in efficiency improvements. Moreover, competitive companies have the prerogative to increase management salaries, pay higher dividends to their investors, make investments in business operations, and/or reduce customer prices.

Combine these factors, and one can appreciate why it is no easy task to provide a simple answer to the simple question, "does competition lead to lower prices?" In most cases, the only correct answer is "it depends."

Perhaps because of these complicating factors, politicians in a number of U.S. jurisdictions that have passed restructuring legislation have insisted on mandated price reductions. Legislatively mandated 10-15% price reductions targeted at small residential customers, combined with a price freeze for everyone else, appears to be a popular political formula. It guarantees the support of a majority of the voters, while permitting larger customers to cut special deals with competing suppliers—something they will demand anyway. Some customers are made better off, while nobody is made worse off.

A 1999 report titled, *The Impact of Competition on the Price of Electricity,* conducted by J. A. Wright and Associates of Marietta, GA, supports the notion that legislatively mandated price reductions may be the *only* pragmatic way to guarantee immediate lower prices. The report, which is focused on competitive markets in California, Massachusetts, and Rhode Island, concludes that the lower prices initially experienced were the result of legislative mandates, not competitive market forces. The report, however, is not critical of competition. It points out that most of the benefits of competition are yet to come—once the transition period is over and utility's stranded costs have been written off.

Moreover, the report points out that, even setting the recovery of stranded costs aside, the costs of transitioning to a competitive electricity market are significant—and tend to be overlooked or underestimated. Finally, there are other subtle costs associated with a restructured market, including more volatile prices.

Why Do Competitive Markets Need a Regulator?

Many countries do not have a well-functioning, independent regulatory authority. All decision making, rate setting, and investment planning is done within the same central bureaucracy. Since they have always done things in this way, the question comes up why change. In other cases, naïve policymakers may assume that market discipline should self-regulate competitive markets, controlling prices and player's behavior. The experience of liberalized markets clearly suggests otherwise:

- **Myth?** – A well-designed, competitive market should be able to operate without much regulatory oversight, sustained by powerful competitive forces. Right? Wrong.
- **Soccer analogy** – To understand why, a sport analogy may be helpful. Consider a competitive game, say soccer. It has very well-known and highly defined rules which specify how the game is to be played, the number of players, what each can and cannot do, how one team can score against the other, and so on. On the surface, it would seem that experienced teams should be able to play without a referee. Obviously, this is not the case. The same is true of practically all other games, including chess.
- **What is the role of the referee**? To ensure that the rules of the game are adhered to, and there is no cheating. To keep the game fair, to prevent one team from abusing another, to keep the playing field *level*, as the saying goes. The function of the regulator is identical to that of a referee – to interpret the rules and to enforce them. To catch cheating, misbehaving, disorderly conduct, and otherwise ensure a fair game.
- **What does it take to be an effective referee?** For a referee to be effective, s/he must have ultimate and absolute authority. Moreover, s/he must be fully independent of political or other pressures. The same principles apply to a regulator. In the absence of authority and independence, no regulator can function properly.

Sobering Experiences

The realities of newly restructured markets, notably the chilling problems experienced in California in 2000-01, have had a sobering effect on the thinking of regulators across the United States.. According to a survey of 46 regulatory agencies[7], U.S. regulatory agencies by a thin margin believe that consumers are better served under the *regulated* monopoly model, still prevailing in many states. Three-quarters of respondents in the survey said that events in California have slowed or stopped deregulation in their jurisdiction. A surprising 40% said their agency lacks the *powers, tools*, and *resources* to prevent a California-style meltdown.

In another recent survey, conducted by Standard and Poor's and RKS Research and Consulting, many regulatory agencies identified the unclear jurisdiction between the federal and state-level regulatory agencies as a major unresolved issue. In the case of California, unclear jurisdictional issues delayed the introduction of many important remedies that could have eased the ensuing crisis when problems first started in 2000[8].

The current push to create regional transmission organizations (RTOs), by the Federal Energy Regulatory Commission (FERC), will only make these turf issues more contentious. In summarizing the survey findings, Richard W. Cortright, Jr., Director of Standard and Poor's says, "This report provides a clear picture of a regulatory community in the midst of a difficult transition."

As described below, the word *deregulation* has become a dirty word in some circles. A report recently published by the Consumer Federation of America concludes that *deregulation has been a costly failure in the United States*. Another study by the Natural Resources Defense Council (NRDC), prepared for the Silicon Valley Manufacturing Group, concludes that California would have had a bleak summer in 2001 had it not been for remarkable voluntary conservation efforts of consumers.

Is Deregulation a Dirty Word Now?

The fiasco in California has had two consequences; one positive, one not so:

- Policymakers in other countries and states now have a model of how things may go wrong – and its disastrous consequences. This is a hugely positive contribution.
- The worldwide momentum towards liberalizing electricity markets has suffered a serious blow in many places, as regulators take time out to see if similar things are likely to happen to them. In the process, deregulation has become a dirty word. This is unfortunate.

In the United States, for example, several states have now delayed the opening of their markets pending a review of the lessons from California. These include Nevada and New Mexico, but also states geographically removed including Arkansas, Minnesota, Oklahoma, and North Carolina.

On a positive note, many states have taken special measures to avoid the problems that have plagued California. For example, politicians in Texas, which opened its market in January 2002, made sure that their system would not experience the problems of the Golden State. Others like Wisconsin are working on beefing up their transmission network to avoid the transmission bottlenecks that plague California.

Costs and Benefits

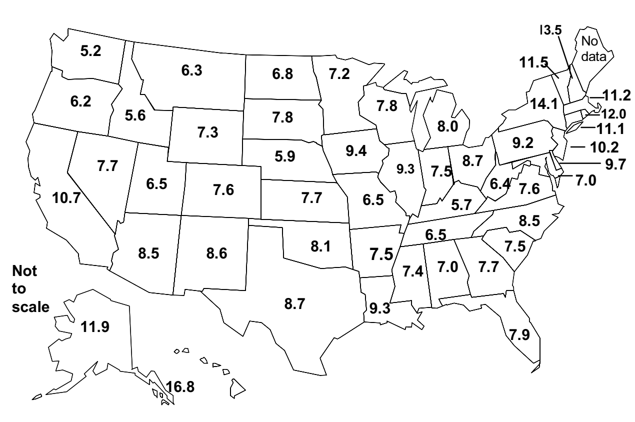
Another important question, which did not seem as important in earlier, naïve days of deregulatory stampede, is that of the costs and expected benefits of introducing competition. As the experience of California suggests, deregulation is not necessarily cheap, nor risk free. Hence, the policymakers must ask many hard questions about the expected benefits. Even if the expected benefits outweigh the costs, one must ask

Table 3
Switching to a Competing Supplier
Switchover rates in states with total or partial retail competition

State	Total Customers	# Using Alternative	% Alternative
Pennsylavnia	4,600,000	574,661	12.5
Ohio	3,900,000	204,868	5.3
New York	5,503,003	189,352	3.4
Maryland	1,831,372	38,456	2.1
Texas*	5,300,000	90,553	1.7
Virginia*	2,600,000	34,000	1.3
New Jersey	3,110,701`	35,094	1.1
California*	10,424,143	64,787	0.6
District of Columbia	198,258	1,056	0.5
Maine	684,656	2,090	0.3
Massachusetts	2,200,000	981	0.04
Rhode Island	460,500	1	0.0002
Delaware	300,000	0	0
Michigan	3,800,000	0	0

* Residential choice is currently limited to a pilot program or otherwise available only in some areas. In California, retail competition has ended.
Source: *The Wall Street Journal*, September 17, 2001.

Figure 2
U.S. Retail Electricity Prices*
(per kilowatt hour)



Average retail electricity prices in the US, Oct 2000
Source: Energy Information Administration, data for Oct 2000
* Prices in California have gone up by as much as 40% or more since the recent crisis has led to two price increases.

if these benefits would automatically accrue and inevitably lead to lower prices.

There is also the issue of the *incidence of costs* – stranded and otherwise – and the *distribution of benefits*. These are not trivial questions. Many industry observers, having studied liberalized markets, have concluded that the there may be little, if any, net gain from extending competition to the retail markets[9]. These critics correctly point out that most of the benefits of competitive markets are in the wholesale market and may be captured at relatively little cost.

The benefits of extending competition to small customers, the critics argue, tend to be relatively small – while the costs are quite high. According to this line of thought, competition may be introduced in stages, starting with the wholesale market, and by allowing large customers to engage in bilateral contracts. Smaller customers may have to wait or selectively be given a chance to participate. The switchover rates (see Table 3) among residential customers have generally been low, and the savings relatively small considering the costs. The reasons are easy to explain. The potential savings to small consumers may simply not be worth the bother.

Is There a Net Gain in all This Pain?

The National Audit Office (NAO), the watchdog for the UK's parliament, published a report suggesting that the costs of introducing competition in the domestic supply business have virtually wiped out all the benefits. The NAO report concluded that the savings to customers have amounted to roughly £143 million/year ($215 million). Not a huge amount, but respectable. But the costs of introducing competition, which has been passed on to the same customers, has been around £121 million ($182 million), making the *net* annual savings a measly £22 million ($33 million). NAO says that this small net benefit is likely to be lost due to additional costs of "*sorting out the remaining problems with the domestic competition systems*." These costs are yet to be quantified, and may exceed the net benefits. Problems and cost over-runs associated with various IT, settlement, and billing systems have been excessive. The most common and persistent problem is switching customer accounts when they change suppliers – which they do often[10].

If deregulation is pursued primarily to harmonize regional price disparities, such as those prevailing across the United States (Figure 2) and in Europe, there may be other ways to accomplish this objective. The point of the argument is to ask the right questions – and be realistic about the answers. Everyone now realizes that market liberalization is not a panacea, and will not solve all the industry's ills. It has significant costs, risks, and may occasionally backfire.

Market Structure and Market Performance

Assuming, for the moment, that a decision has been reached to liberalize the electricity market, there are a host of difficult *how to* questions. For example, how to structure the competitive market and establish the market rules. These go to the heart of many of the problems now plaguing poorly functioning markets such as California.

The following section lists some of the critical market structure issues. Getting any one item on the list wrong, can wipe out all the gains from getting all the others right. There is a strong correlation between market structure and market performance – as one would expect.

Market Structure Issues: Points to Ponder

- centralized mandatory pool, voluntary bilateral trade, or hybrid system
- combining market operator (MO) and transmission system operator (TSO) function into one organization or keeping them separate
- design and implementation of the competitive wholesale auction
- design and implementation of real-time balancing market including the provision of ancillary services
- requirements for functional unbundling of vertically integrated companies or accounting ring-fencing
- design and enforcement of open access transmission network and non-discriminatory transmission tariffs

- design and implementation of unbundled retail bills
- the design and implementation of settlement system for generators, distributors, and competing retailers and resellers
- design and implementation of demand-side bidding into the wholesale auction and/or the real-time balancing market
- design and implementation of transmission pricing and congestion management schemes (e.g., zonal, nodal, locational marginal pricing or other)
- rules governing customer switching, metering, billing, and settlements
- design and implementation of load profiles or requirements for interval meters and real-time pricing
- rules and policies governing mergers and acquisitions
- rules and policies on dealing with issues of market power and unfair pricing or marketing practices
- rules governing the statutory authority of the regulator, market monitor, and enforcement agencies
- policies on customer protection, service quality standards, and consumer education
- policies and funding mechanisms to support social goods (e.g., low income assistance, energy efficiency, R&D, renewable energy, etc.)

The right answers to the right questions vary depending on the prevailing circumstances, existing infrastructure, history, political, economic, socio-demographic and even geographical factors. For example, in many developing countries, the private equity markets are non-existent or feeble. In this case, policymakers wishing to introduce competition among power stations to increase operating efficiencies may not have the option to liberalize the market. They may have to resort to corportization where individual power stations remain as state-owned enterprises in government hand; but each station is made into a separate profit and loss center, and forced to compete with its peers in a competitive wholesale power auction. With properly defined market rules and incentives, such a scheme can work quite well, mimicking a fully liberalized market with competing private investors.

Experience in South Africa, New South Wales and Australia, for example, demonstrates that similar schemes may work in other countries. In Norway, a highly successful competitive market, most of the industry is still state-owned.

Vertical Integration, Harmonization, and Other Matters

Aside from market structure and design issues, is the question of what to do with the existing vertically integrated nature of the industry prevailing in many parts of the world. Most experts agree that it would be hard to have meaningful competition in a market with powerful incumbents that own and/or control strategic assets such as generation or transmission. One way to resolve this problem is to require *functional unbundling* – forcing existing players to divest – or at least give up operational control – of critical assets[11].

Similarly, it is generally agreed that competitive markets need an *independent* system operator or its equivalent. Finally, open access to transmission and distribution assets with transparent and non-discriminatory tariffs is generally accepted as a must. The European Union's directive on liberalization is generally criticized as being overly lax and/or vague on these central issues.

Another important issue is the harmonization of prices and regulations across state boundaries. This is a major problem in countries (e.g., U.S.) or continents (e.g., Europe) with vastly different systems and regulatory regimes. How can federal (in the case of the U.S.) or European Union (in the case of Europe) policymakers introduce competition in an otherwise heterogeneous industry and harmonize prices and regulations across state boundaries? This has proven to be a difficult problem in North America, eluding an answer up to now. Likewise, it has kept the EU regulators in Brussels frustrated for many years. The experience of Germany, the largest fully liberalized European energy market, suggests that in the absence of unbundling, open access to transmission grid, and a regulator, liberalized markets do not achieve their full potential.

Germany's Liberalized Electricity Market: Half Full Or Half Empty?

Germany opened both its electricity and natural gas markets in 1998. The German brand of liberalization, however, is unique in many respects. For example:

- there is no requirement to physically *unbundle* generation, transmission, and distribution—leaving the dominant incumbents in a strong position to control the market;
- there is no independent system operator (ISO), nor a central market operator (MO) to set market clearing prices;
- access to the transmission network is *theoretically* open with access charges to be negotiated by parties involved in transactions;
- there is *no regulator*, instead they rely on the good faith of the parties to negotiate transactions on a case-by- case basis.

So, how well is the German market performing after four years? The answer is the proverbial *the glass is half empty or half full*—depending on how one looks at it. The glass is half full because:

- all consumers have the right to switch suppliers and 3% of residential customers, and over 10% of industrial customers have taken advantage of customer choice;
- the transmission grid is *theoretically* open for use by third parties and some are taking advantage of this;
- there is *virtual* competition in the generation sector and a few new IPPs have come into play; and,
- retail electricity prices have fallen—significantly for most customers—although prices have firmed recently.

VDEW, the association of German electricity companies, estimates that residential consumers have collectively saved $1.8 billion and the industry some $5 billion since 1998. Customers have a choice, and this has led to major efforts to improve service quality. Not bad for starters.

The glass, however, is half empty because:

- industrial prices, which initially dropped by 30% or more, are now rising;
- electricity trading, which theoretically should be flourishing, represents a mere 2-3% of the physical volume of

consumption compared to 25% in the Scandinavian Nordpool, and much higher volumes in other liberalized markets;

- grid access charges, due to the nature of bilateral negotiation process, are incredibly slow and opaque;
- the lack of market transparency and the one-on-one nature of transactions means that no one knows the prevailing prices;
- there have been isolated complaints from IPPs and others that it is difficult or impossible to gain access to utility grids at any price;
- six big generators (RWE, e.ON, EnBW, Veag, Bewag, and HEW), who also control the country's high voltage grid, account for 80% of the generation;
- the dominant generators have, shall we say, strongly discouraged retailers from switching suppliers by offering highly attractive, long-term contracts; and,
- newcomers have had a hard time establishing a foothold due to bureaucratic and contractual hurdles that binds parties to the big incumbents and lack of price transparency.

The six big dominant players, who control and/or own many other players, are extremely powerful and can effectively thwart the efforts of their competitors. Germany's anti-cartel office, the closest thing it has to a regulator, has published a list of mischiefs allegedly perpetrated by the big suppliers against their competitors, including

- illegal switching of rates charged by municipal utilities (*Stadwerke*);
- requiring highly restrictive contractual terms to prevent access to local distribution lines;
- restricting access to customers' meters; and,
- making it difficult for competitors to offer a simple and single contract covering both energy and delivery charges.

The European Union's (EU) Electricity Directive in Brussels has repeatedly suggested that Germany, like all other EU member countries, appoint an independent market regulator that can set and enforce the rules for uniform network access charges. The EU must also insist on unbundling of existing players, and while they are at it, why not set up an ISO and an MO to make the glass full, not just half full.

Similarly, California's unsuccessful experience offers many useful insights that might not have been obvious until recently. The California experience, for example, shows that there are so many ways to get things wrong, a feat that was accomplished in the Golden State with rather serious consequences (see Table 4). Policymakers in other states and the rest of the world are studying California as a model to avoid.

Although there is a tendency to trivialize the issues, and to draw hasty – and sometimes wrong – conclusions, this re-examination is warranted. For example, many observers of the California market quickly concluded that heavy reliance on the spot market is to be avoided at all cost. Others point to the success of the Pennsylvania, New Jersey, and Maryland (PJM) Pool as a counter example. Spot markets aren't necessarily evil, but like everything else in life, work best when taken in moderation.

Transition and Implementation: The Final Hurdles

Implementation and transition issues are equally daunting. Even with the best market design and market structure, there are many ways to end up with a poorly functioning market due to poor implementation or a botched-up transition strategy. These problems are equally daunting, whether one is dealing with a developing or a developed country. Since restructuring radically changes the rules of the game and upsets the balance of power among existing players, powerful groups with vested interests tend to intervene through the political process. The result is often a political compromise

Table 4
Lessons from California: There are So Many Ways to Screw Things Up

Avoid heavy reliance on volatile spot market – This may sound so obvious as to be redundant. But it was not so obvious to California's market designers in 1996.	Other markets, say oil or natural gas, rely heavily on futures and options to handle price volatility. How *could* any market, especially one as volatile as electricity, and with no inventory, work otherwise?
Pay for capacity –California's PX auction did not pay generators for capacity. It paid for energy, only when a given unit was used. (The ISO, of course, pays for capacity in the ancillary services market.)	This scheme works well – from the customers' point of view – when capacity is plentiful and demand is low; but not when demand is high and supplies are tight. It certainly did not encourage additional investments in capacity when prices were low in 1998-99.
Don't deregulate wholesale prices while keeping retail tariffs frozen – This has driven the utilities in California to the brink of insolvency.	The regulators in California unconsciously created the worst of all possible worlds, a self-contradictory paradigm when wholesale prices were allowed to go high, while retail prices remained frozen.
Don't leave demand out of the equation – The California market would have self-corrected itself to a great extend had customers been exposed to higher prices.	The California market was at best a half market. Consumers had no incentive to respond to prices even when they were exorbitantly high.
Don't deregulate if network is already constrained – If the network is already severely constrained, be it in generation or transmission capacity, competition is likely to *increase* prices.	A good time to introduce competition is when there is excess capacity. This can result in lower prices. More importantly, it will provide a safety period during which the kinks in the market rules can be worked out.
Don't promise lower prices – Politicians love to make promises they cannot keep, including lower electricity prices.	If lower prices materialize, so much the better. But it is not a good idea to build up customers' expectations.
Don't panic when generators make profits –	In capitalistic systems, high prices and profits provide important signals to investors.

that pleases no one and offers too many loopholes and too many exceptions.

In the case of California, many experts blame the state's politically expedient restructuring law, known as Assembly Bill 1890, as the main culprit for the ensuing problems. AB 1890 unanimously passed both houses of the California Legislature, and was signed by the then Republican Governor Pete Wilson amidst grand fanfare in 1996. Virtually no laws ever pass with such a strong base of support. Is it possible that too many political compromises were made to get everyone's support for the bill? As any seasoned politician would attest, if a law passes unanimously, then it must have too many loopholes and too many giveaways.

Finally, there is the issue of provision of social goods, long provided and paid for through hidden subsidies. These include massive cross subsidies among and across customer groups, subsidies for farmers, low-income customers, pensioners, selected industries, and so on. There are subsidies for renewable energy, for local coal, for vocal unions, etc. Some subsidies may be socially justified and must be sustained. In such cases, new ways must be found to fund and sustain the programs. Private industry is not likely to offer many social goods free of charge. Restructured markets can be structured to continue to provide social goods through special levies, license fees, taxes, and other charges. But these must be explicit, and their incidence designed not to interfere with the competitive aspects of the market, nor to disadvantage some players *vis-à-vis* others.

The Road Ahead

Despite enormous bad publicity coming out of California, Brazil, and a few other problem areas, the experience with market restructuring has been generally positive. Many markets, like the one in the Nordic countries, are regarded as highly successful. The market in England and Wales, which initially suffered from problems associated with the influence of two dominant generators, has now been redesigned. Other markets around the world may be characterized as moderately successful. Even in cases where there are a few known shortcomings, the overall experience has been worth the effort.

Moreover, markets have made us aware of new opportunities, just as it has identified new perils and challenges. One of the enormously positive lessons of restructured markets is that there is a new recognition of the significance of *elasticity* of demand[12]. There is now a much better understanding that customer demand can – and should – play a more active role in balancing supply and demand in real time. Markets provide the incentives – through market price volatility – to influence demand when and where it is cost-effective to do so.

Beyond these generalities, one can draw a list of what to do – and avoid – from restructured markets, which have experienced serious problems so far. The following is one such list from the California experience.

- Don't fix it if it ain't broke
- Don't restructure if capacity is tight
- Don't over-promise what you cannot deliver
- Don't push the process beyond what is reasonable and necessary
- Don't liberate part of the market, while keeping the rest regulated
- Make sure somebody is in charge when things go wrong – and everybody knows who it is
- Closely monitor the market for signs of trouble – and be prepared to take decisive action before problems get out of hand
- Don't over-rely on the spot market
- Encourage risk-hedging
- Ask if retail competition is necessary and cost-justified
- Don't forget demand elasticity
- If the *market* is supposed to take care of demand and invest in infrastructure, make sure the *market* receives correct and clear signals in time to respond
- Test the market rules before they are implemented

Policymakers who do not heed these lessons will only have themselves to blame.

Footnotes

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[10] Power in Europe, 12 January 2001

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EFCEE Discontinues Operation

Pieter vander Meiren has advised the IAEE that the European Federation for Cooperation in Energy Economics (EFCEE) has ceased operation primarily due to the continued unavailability of funding from the European Commission.

The IAEE had loaned the EFCEE $6000 early in its career to assist in getting started. Only $1478 of that loan has been repaid. Unfortunately, IAEE will have to write-off the balance of $4522.

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• **Newsletter**: The IAEE Newsletter, published four times a year, contains articles dealing with applied energy economics throughout the world. The Newsletter also contains announcements of coming events, such as conferences and workshops; gives detail of IAEE international affiliate activities; and provides special reports and information of international interest.

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8/02News

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!!! MARK YOUR CALENDARS — PLAN TO ATTEND !!!

Energy Markets in Turmoil: Making Sense of it All

22nd USAEE/IAEE North American Conference – October 6-8, 2002
Vancouver, British Columbia, Canada – Sheraton Wall Centre Hotel

If you're concerned about the future of the energy industry, this is one meeting you surely don't want to miss. The 22nd USAEE/IAEE North American Conference will detail current developments within the energy industry so that you come away with a better sense of energy security, supply, demand and price. Some of the major conference themes and topics are as follows:

Continental Energy Markets Prospects
Energy Security in the 21st Century
California Fallout: What Useful Lessons Can Be Learned?
Offshore Petroleum Industry: Reflections on Moving Forward
Canada-US Natural Gas Trade
North American Regulation: Are We Getting It Right?
Fossil Fuels and Sustainability: Like Oil and Water?

Volatile fuel prices, market restructuring, globalization, privatization and regulatory reform are having significant impacts on energy markets throughout the world. Most major energy industries are restructuring through mergers, acquisitions, unbundling and rebundling of energy and other services. This conference will provide a forum for discussion of the constantly changing structure of the energy industries.

At this time, confirmed and/or invited speakers include the following:

Adam Sieminski, Deutsche Banc Alex Brown
Guy F. Caruso, Energy Information Administration
Merete Heggelund, Norsk Hydro Canada
Moia Cahill, PanMaritime
Michael Rodgers, Petroleum Finance Company
Hillard G. Huntington, EMF, Stanford University
Perry P. Sioshansi, Henwood Energy Services
Anjali Sheffrin, California ISO
Jim Tracy, Sacramento Municipal Utility District
Richard Hyndman, Canadian Assn. of Petro. Producers
Michael R. Jaske, California Energy Commission
Mark K. Jaccard, Simon Raser University
Robert Williams, Princeton University
Edward Bogle, Talisman Energy, Inc.
Leonard L. Coburn, U.S. Department of Energy
Robert E. Ebel, Center for Strategic & Int'l Studies
Kathy Arthurs, Chevron Texaco
Elisabeth Harstad, Det Norske Veritas
Campbell G. Watkins, University of Aberdeen
Vito Stagliano, Calpine Corporation
Arthur O'Donnell, Editor, *California Energy Markets*
Gary Stern, Southern California Edison
Michelle Michot Foss, University of Houston
Shirly Neff, U.S. Senate, Energy & Nat. Res. Committee
Peter Ostergaard, British Columbia Utilites Comm.
Gerard J. Protti, Pan Canadian Energy Corporation
Jim Dinning, TransAlta Corporation

John Reid, CEO of BC Gas will be the luncheon keynote speaker on Monday, October 7. **Larry Bell,** Chief Executive Officer, BC Hydro will address the conference dinner on October 7. In addition, 24 concurrent sessions are planned to address timely topics that affect all of us specializing in the field of energy economics. Honourable **Richard Neufeld**, British Columbia Minster of Energy and Mines will officially open the Conference.

Vancouver, B.C. is homebase to many energy companies and a great place to meet. Single nights at the Sheraton Wall Centre Hotel are $224.00 Cdn. (approximately $150.00 US dollars per night) Contact the Sheraton Hotel at 604-893-7120, to make your reservations). Conference registration fees are $500.00 for IAEE members and $600.00 for non-members.

For further information on this conference, please fill out the form below and return to IAEE Headquarters.

Energy Markets in Turmoil: Making Sense of it All
22nd Annual North American Conference of the USAEE/IAEE

Please send me further information on the subject checked below regarding the USAEE/IAEE Conference.

_____ Registration Information _____ Sponsorship Information ____ Accommodation Information

NAME: ______________________________
TITLE: ______________________________
COMPANY: ______________________________
ADDRESS: ______________________________
CITY,STATE,ZIP: ______________________________
COUNTRY: ____________________ Phone/Fax: ____________________

USAEE/IAEE Conference Headquarters, 28790 Chagrin Blvd., Suite 350, Cleveland, OH 44122 USA
Phone: 216-464-2785 Fax: 216-464-2768 Email: usaee@usaee.org
Visit the conference on-line at: **http://www.usaee.org/energy/**

Future IAEE Events

October 6-8, 2002	22nd USAEE/IAEE North American Conference Vancouver, BC, Canada *Sheraton Wall Centre Hotel*
June 5-7, 2003	26th IAEE International Conference Prague, Czech Republic *Dorint Prague Hotel*
October 19-21, 2003	23nd USAEE/IAEE North American Conference Mexico City, Mexico *Camino Real Hotel*

Publications

Energy Convergence: The Beginning of the Multicommodity Market, Peter C. Fusaro (June 2002). Price: $79.95. Contact: URL: www.energymediagroup.com

What Went Wrong at Enron, Peter C. Fusaro (July 2002). Price: $14.95. Contact: URL: www.energymediagroup.com

Distributed Generation: The Power Paradigm for the New Millenium, Anne-Marie Borbely and Jan Kreider (Peter Fusaro contributor). Contact: URL: www.energymediagroup.com

Global Markets & National Interests: The New GeoPolitics of Energy, Capital and Information, Peter Fusaro et al, (June 2002). Contact: URL: www.energymediagroup.com

Oil and Gas: Crises and Controversies 1961-2000 Volume 1 – Global Issues, Peter R. Odell (2001). 494 pages. Price: #55.50. Contact: Multi-Science Publishing Co. Ltd., 5 Wates Way, Brentwood, Essex CM15 9TB, UK. Fax: 44-1277-223453. Email: mscience@globalnet.co.uk URL: www.multi-science.co.uk

Climate Policy After Kyoto, Tor Ragnar Gerholm (1999). 170 pages. Price: #24.50. Contact: Multi-Science Publishing Co. Ltd., 5 Wates Way, Brentwood, Essex CM15 9TB, UK. Fax: 44-1277-223453. Email: mscience@globalnet.co.uk URL: www.multi-science.co.uk

Liberalisation of Italy's Energy Markets, Peter Enav. Price: #595.00 Contact: CWC Publishing Limited, Tyers Gate, London SE1 3HX, United Kingdom. Phone: 44-20-7089-4200. Fax: 44-20-7089-4201. Email: publishing@thecwcgroup.com URL: www.thecwcgroup.com

Energy Infrastructure Security: Protecting Staff, Assets & Operations from Potential Sabotage & Terrorist Threat (2002). Contact: Utilis Energy LLC. Phone: 917-371-8161. Fax: 413-604-5615. Email: info@utilisenergy.com URL: www.utilisenergy.com/casestudiesensec.html

Annual Oil Market Forecast & Review 2002. Contact: Centre for Global Energy Studies. Phone: 44-20-7309-3612. URL: www.cges.co.uk/AR2002.htm

Iran – Understanding Iran's Economy and its Oil and Gas Industries, Dr. Manouchehr Takin (2002). Contact: Centre for Global Energy Studies. Phone: 44-20-7309-3610. URL: www.cges.co.uk/iran2002.htm

Consumer Guide to Home Energy Savings 7th Edition. (1999). 244 pages. Price: $8.95. Contact: ACEEE Publications, 1001 Connecticut Avenue, NW Suite 801, Washington, DC 20036. Phone: 202-429-0063. Fax: 202-429-0193. Email: ace3pubs@ix.netcom.com URL: www.acee.org/pubs

Guide to Energy-Efficient Commercial Equipment 2nd Edition, M. Suozzo, J. Benya, M. Hydeman, P. DuPont, S. Nadel and N Elliott (2000). 185 pages. Price: $35.00. Contact: ACEEE Publications, 1001 Connecticut Avenue, NW Suite 801, Washington, DC 20036. Phone: 202-429-0063. Fax: 202-429-0193. Email: ace3pubs@ix.netcom.com URL: www.acee.org/pubs

Energy Efficiency and the Environment: Forging the Link, E Vine, D Crawley, and P. Centolella (1991). 418 pages. Price: $29.00. Contact: ACEEE Publications, 1001 Connecticut Avenue, NW Suite 801, Washington, DC 20036. Phone: 202-429-0063. Fax: 202-429-0193. Email: ace3pubs@ix.netcom.com URL: www.acee.org/pubs

Transportation, Energy, and Environment: How Far Can Technology Take Us? J. DeCicco and M. Delucchi (1997). 278 pages. Price: $33.00. Contact: ACEEE Publications, 1001 Connecticut Avenue, NW Suite 801, Washington, DC 20036. Phone: 202-429-0063. Fax: 202-429-0193. Email: ace3pubs@ix.netcom.com URL: www.acee.org/pubs

Transportation and Global Climate Change, Danilo Santini and David Greene (1993). 357 pages. Price: $31.00. Contact: ACEEE Publications, 1001 Connecticut Avenue, NW Suite 801, Washington, DC 20036. Phone: 202-429-0063. Fax: 202-429-0193. Email: ace3pubs@ix.netcom.com URL: www.acee.org/pubs

U.S. Utility and Non-Utility Power Directories, (2000-2001). Price: $1090.00. Contact: PMA, 3304 Dye Dr., Falls Church, VA 22042. Phone: 703-641-0613. Fax: 703-641-9265.

International Review of Applied Economics – Volume 15, Number 3, M. Sawyer, S. Gazioglu, J. Michie, P. Arestis, K. Cowling, R. Smith (July 2001). Price: $161.00. Contact: Routledge, Taylor & Francis Inc, Customer Services, 325 Chestnut St, 8th Flr, Philadelphia, PA 19106. Phone: 215-625-8900. Fax: 215-625-8914. Email: journal.orders@tandf.co.uk URL: www.tandf.co.uk/journals

Global Oil and the Nation State, Dr. Bernard Mommer. 255 pages. Price: #29.50. Contact: Mrs. Margaret Ko, Oxford Institute for Energy Studies, 57 Woodstock Road, Oxford OX2 6FA, United Kingdom. Phone: 44-0-1865-311377. Fax: 44-0-1865-310527. Email: publications@oxfordenergy.org URL: www.oxford energy.org

Calendar

6-7 August 2002, Derivatives for Energy Professionals at Houston, TX. Contact: Conference Registration, Kase and Company, 1750 West Loop South, Houston, TX, 77027, USA. Phone: 505-237-1600 Email: kase@kaseco.com URL: www.kaseco.com/classes/derivatives.htm

19-23 August 2002, Cogeneration Technology at Madison, WI. Contact: Conference Coordinator, College of Engineering University of Wisconsin-Madison, The Pyle Center, 702 Langdon Street, Madison, Wisconsin, 53706, USA. Phone: 800-462-0876. Fax: 800-442-4214 URL: http://epdweb.engr.wisc.edu/brochures/A953.html

20-21 August 2002, Drill Cuttings and How Best to Manage Them at Aberdeen, Scotland. Contact: Hanno Kunzmann, Assistance, IQPC, London, Anchor House, 15-19 Britten Street, London, SW3 3QL, UK. Phone: 44(0)20 7368 9300. Fax: 44(0)20 7368 9301 Email: enquire@iqpc.co.uk URL: www.iqpc.co.uk/1848a

1-5 September 2002, 17th World Petroleum Congress at Rio de Janeiro. Contact: Conference Organizer, JZ Congressos, Rua Conde de Iraja, 260/2 andar Botafogo, Rio de Janeiro, RJ, 22271-020, Brazil. Phone: 55-21-2539-2706. Fax: 55-21-2527-6297 URL: www.wpc2002.com

1-1 September 2002, Pan-European Electricity Trading Forum at Central London. Contact: Andrew Barnes, Registrations Manager, Marcus Evans Capital Markets, 4 Cavandish Square, London, W1G 0BX, UK. Phone: 44 20 7647 2343. Fax: 44 20 7647 2279 Email: capitalmarkets3@marcusevansuk.com URL: www.marcusevans.com

2-4 September 2002, International Discussion Forum on Technology Evolution and Future European Electricity Markets

(continued on page 36)

Calendar *(continued from page 35)*

at London, UK. Contact: Paule Stephenson, TELMARK Co-ordinator, School of Engineering, Kingston University, Roehampton Vale, Friars Avenue, LONDON, SW15 3DW, UK. Fax: +44 208 547 7992 Email: telmark@kingston.ac.uk URL: http:/ www.telmark.org

17-18 September 2002, Asia Regional Farmout & Exploration Promotion Forum 2002 at Sheraton Suites, near the Galleria, Houston, USA. Contact: Babette van Gessel, Group Managing Director, Global Pacific & Partners, 2nd Floor, Regent Place, Cradock Avenue, Rosebank, Johannesburg, 2196, South Africa. Phone: 27 11 778 4360. Fax: 27 11 880 3391 Email: info@glopac.com URL: www.petro21.com

23-24 September 2002, 2nd Annual Middle East & Central Asia Oil & Gas 2002 at Marriott Hotel, Marble Arch, London, UK. Contact: Babette van Gessel, Group Managing Director, Global Pacific & Partners, 2nd Flr, Regent Place, Cradock Ave, Rosebank, Johannesburg, 2196, South Africa. Phone: 27 11 778 4360. Fax: 27 11 880 3391 Email: info@glopac.com URL: www.petro21.com

23-24 September 2002, 25th Annual Platts Coal Marketing Days at Westin Convention Center - Pittsburgh, PA. Contact: Platts Global Conferences, Platts, 3333 Walnut Street, Boulder, CO, 80301, USA Email: plconf@platts.com URL: www.conferences.platts.com

23-24 September 2002, Platts PJM Regional Conference at Hyatt Regency on the Inner Harbor - Baltimore, MD. Contact: Platts Global Conferences, Platts, 3333 Walnut Street, Boulder, CO, 80301, USA Email: plconf@platts.com URL: www.conferences.platts.com

24-25 September 2002, Sand Control and Management: A Holistic Approach at The Cafe Royal, London. Contact: Hanno Kunzmann, Assistance, IQPC, London, Anchor House, 15-19 Britten Street, London, SW3 3QL, UK. Phone: 0044(0)20 7368 9300. Fax: 0044(0)20 7368 9301 Email: enquire@iqpc-oil.com URL: wwwiqpc-oil.com/1851

25-27 September 2002, Herold Pacesetters Conference at Hyatt Regency in Old Greenwich, CT. Contact: Bianca Smothers, Conference Director, John S. Herold Inc., 14 Westport Ave., Norwalk, CT, 06851, USA. Phone: 203-847-3344. Fax: 203-847-5566 Email: bsmothers@herold.com URL: www.herold.com/ confmenu.htm

25-26 September 2002, Mexican Investment Opportunities: Oil, Gas & Energy 2002 at Sheraton Suites Houston, near the Galleria, Houston, USA. Contact: Babette van Gessel, Group Managing Director, Global Pacific & Partners, Private Bag X61, Saxonwold, Gauteng, 2132, South Africa. Phone: 27 11 7784360. Fax: 27 11 8803391 Email: info@glopac.com URL: www.petro21.com

25-27 September 2002, Petrolac 2002 - Energy Ministers Meeting at Houston, TX. Contact: Information, Petrolac, USA Email: contact@petrolac.com URL: www.petrolac.com

26-27 September 2002, Portfolio Optimisation in Oil, Gas and Chemicals at The Cafe Royal, London. Contact: Conferences Producer, IQPC, London, Anchor House, 15-19 Britten Street, London, SW3 3QL, UK. Phone: 0044(0)20 7368 9300. Fax: 0044(0)20 7368 9301 Email: enquiry@iqpc-oil.com URL: www.iqpc-oil.com/GB-1860/ediary

27-29 September 2002, New Directions in the International Conference on Earth Sciences and the Humanities: Experiments in Interdisciplinarity at Colorado School of Mines, Golden, Colorado USA. Contact: Robert Frodeman, Professor, Colorado School of Mines, Liberal Arts & International Studies, Stratton Hall 301, Golden, Colorado, 80401, USA. Phone: (303) 273-3585. Fax: (303) 273-3751 Email: rfrodema@mines.edu URL: www.mines.edu/newdirections

IAEE Newsletter

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