USAEE

UNITED STATES ASSOCIATION *for* ENERGY ECONOMICS

Dialogue

Vol. 17, No. 2 August 2009

USAEE Mission Statement

The United States Association for Energy Economics is a nationwide non-profit organization of business, government, academic and other professionals that advances the understanding and application of economics across all facets of energy development and use, including theory, business, public policy, and environmental considerations.

To this end, the United States Association for Energy Economics:

- Provides a forum that includes practitioners, teachers and students of energy economics and related disciplines for the exchange of ideas, advances and professional experiences.
- Promotes the development and education of energy professionals.
- Fosters an improved understanding of energy economics and energy related issues by all interested parties.

CONFERENCE OVERVIEW

Energy is a key driver of economic growth, something the world is desperately looking for in the current crisis. At the same time, traditional energy supply is reaching its limits. Many energy sources have to be developed to meet the 21st century environmental, social and economic challenges.

How can unconventional hydrocarbons (oil sands, shale gas and others) and carbon sequestration help bridge the gap between conventional oil, gas, coal and nuclear power and the most promising renewable energy sources – biomass, hydro, wind, geothermal, and solar? Furthermore, how can market reforms promote more energy efficiency?

This conference will bring together key players in the North American energy sector to address these questions and many others in plenary and concurrent sessions.

Those interested in organizing sessions should propose a topic and possible speakers to Pierre-Olivier Pineau, Concurrent Session Chair (p) +1 514-340-6922, (e) *pierre-olivier.pineau@hec.ca*

This conference will also provide networking opportunities through workshops, public outreach and student recruitment.

HOSTED BY: CAEE – Canadian Association for Energy Economics / Association canadienne d'économique de l'énergie

WITH SUPPORT FROM: USAEE – United States Association for Energy Economics; IAEE – International Association for Energy Economics, www.iaee.org; AMEE

TOPICS TO BE ADDRESSED INCLUDE:

Conventional Oil and Gas Issues
- Reserves and access to reserves
- Production and drilling activity
- Fiscal issues: incentive taxation and royalty regimes
- Enhanced recovery with CO_2 injection
- Estimating and forecasting project costs

Unconventional Oil and Gas Issues
- Reserves, resources and possible recovery
- Oil sands production costs
- Heavy oil prospects
- Coalbed methane and shale gas production
- Environmental footprint

Infrastructure Investments
- New pipelines
- LNG terminals, import/export
- Refining and moving 21st century liquid fuels
- Financing after the credit crisis

Carbon Capture and Sequestration
- Experiences to date
- Links with enhanced oil & gas recovery
- Potential to limit GHG
- Cost and the role of subsidies in CCS

Electricity Generation
- Supply adequacy
- New nuclear developments
- State/provincial regulation and economic distortions
- Ownership and cost of hydropower

Electricity Networks
- Market integration and reforms
- Transmission upgrades and pricing
- Distributed generation
- Smart grids and smart metering innovations

Energy Efficiency
- Measurement and verification
- Link to energy pricing
- Information and other market failures

Climate Change
- GHG emission reduction targets and costs
- Impacts of a cap-and-trade system or a carbon tax
- Developments in carbon-mitigation technologies
- International agreements post-Kyoto
- Cost effectiveness: reduction, sequestration or adaptation

Biofuels
- Regulatory incentives
- Life-cycle energy and economic assessments
- Linkages and competition with the food chain

Renewables in Electricity
- Renewable Portfolio Standards and regulatory approaches
- Wind development: growth and challenges
- Hydropower contribution
- Solar and geothermal technology updates

Energy and Transportation
- Transportation policy and efficiency
- Impact of the automobile crisis on energy demand
- Fuel efficiency standards

Geopolitics
- North American energy inter-dependence
- The future of OPEC
- Natural gas politics
- Persian Gulf security
- Renewable energy and energy security

Energy Poverty
- Access to modern energy services
- Energy prospects for developing countries

Visit our conference website at: http://www.usaee.org/usaee2010/

CALL FOR PAPERS

We are pleased to announce the Call for Papers for the 29th USAEE/IAEE North American Conference to be held October 14-16, 2010 at the Hyatt Regency Calgary hotel, in Calgary, Alberta, Canada. The Deadline for receipt of abstracts is May 21, 2010.

Paper abstracts, giving a concise overview of the topic to be covered and the method of analysis, should be ***one to two pages***. Abstracts should include the following brief sections: (1) overview, (2) methods, (3) results, (4) conclusions, and (5) references.

Please visit http://www.usaee.org/usaee2010/ to download a sample abstract template. NOTE: All abstracts must conform to the format structure outlined in sample abstract template. At least one author of an accepted paper must pay the registration fees and attend the conference to present the paper. The corresponding author submitting the abstract must provide complete contact details – mailing address, phone, fax, e-mail, etc. Authors will be notified by July 9, 2010 of their paper status.

Authors whose abstracts are accepted will have until September 3, 2010, to submit their full papers for publication in the conference proceedings. While multiple submissions by individuals or groups of authors are welcome, the abstract selection process will seek to ensure as broad participation as possible: each speaker is to present only one paper in the conference.

No author should submit more than one abstract as its single author. If multiple submissions are accepted, then a different co-author will be required to pay the reduced registration fee and present each paper. Otherwise, authors will be contacted and asked to drop one or more paper(s) for presentation.

Abstracts **must be submitted online** to http://usaee.org/USAEE2010/submissions.aspx Abstracts submitted by email will not be processed. Please use the online abstract submission form.

STUDENTS

Students may submit an abstract for the concurrent sessions. The deadline for abstracts is May 21, 2010. Also, you may submit a paper for consideration in the USAEE Student Paper Award Competition (cash prizes plus waiver of conference registration fees). The paper submission has different requirements and a different deadline.

The deadline for submitting a paper for the Student Paper Awards is July 8, 2010. Visit http://www.usaee.org/USAEE2010/paperawards.html for full details. Students may also inquire about our scholarships for conference attendance. Visit http://www.usaee.org/USAEE2010/students.html for full details.

TRAVEL DOCUMENTS

All international delegates to the 29th USAEE/IAEE North American Conference are urged to contact their respective consulate, embassy or travel agent regarding the necessity of obtaining a visa for entry into Canada. If you need a letter of invitation to attend the conference, contact USAEE with an email request to usaee@usaee.org.

The Conference strongly suggests that you allow plenty of time for processing these documents.

Note: U.S. citizens attending the 29th USAEE/IAEE North American Conference will need to present a passport upon entry to Canada.

Visit our conference website at: http://www.usaee.org/usaee2010/

President's Message

It is time everybody talked more about Time.

As practitioners, teachers, and students of energy economics, we in USAEE know the usual aims for energy policy. Our supply and use of energy should be: 1) affordable, 2) secure, 3) environmentally acceptable, and 4) adequate to our requirements. We know the demand side of the market equation too, so we understand that efficiency in production and application of energy can play as big a role as the various energy sources in balancing these objectives.

But one goal or another always seems to be elusive, so it is natural to ask how (and *how soon*) we might find a desirable path forward. That is where Time comes in.

Policy planners without a realistic sense of Time may promulgate impractical targets, such as eliminating all U.S. coal-fired power plants within less than a decade. Whether or not it would be sensible to forsake completely our most abundant and (currently) least expensive primary energy source for generating electricity, such a timetable for phase-out would bankrupt most utilities, send power bills soaring, and make regional brownouts unavoidable. It is a non-starter.

Many who accept the measured desirability of stabilizing emissions of potentially global-warming gases by what seems like a distant deadline (such as 2050) fail to recognize the enormity of the challenge. Meeting it will require a prompt start and *timed* benchmarks along the way. Perhaps no one has illustrated this more vividly than Professor Robert Socolow and his associates at Princeton, with their "decarbonization wedges" . . . and even a game, available on line at www.princeton.edu/wedges/ .

Some argue that overly ambitious time-targets serve a useful purpose. Perhaps grand visions create momentum. The State of California, where USAEE was pleased to host the 32nd annual global conference of the IAEE in June, continues to set and miss energy deadlines regularly – for zero-emission vehicles, for its "hydrogen highway network", and so on. Yet California boasts an enviable record for energy efficiency in every sector; and it has created a model for deploying low-carbon and oil-sparing technologies that the Obama administration is proceeding to adapt nationwide. In fairness, however, let us recognize that California imports twice as much of the energy it uses as the average state . . . and its proudly "green" Public Utilities Commission now admits that achieving a proposed 33-percent renewable energy portfolio by 2020 would have to involve a combination of expenditures, luck, and perfect *timing* that looks unlikely.[1]

Personally (and I only say this personally, since USAEE takes no stands on such matters), I think the Waxman-Markey energy bill was improved by toning down its original timetables – which clearly overstretched. I also doubt that the Obama pledge to double U.S. generating capacity using renewable energy by January 2012 will be met; and I am afraid that overpromising in terms of time eventually results in broad skepticism. That discourages investment and blunts progress.

Exaggeration of what we can reasonably expect in specific time frames is not limited to the renewable energy community. Over-enthu-

[1] California Public Utilities Commission, *33% Renewables Portfolio Standard: Implementation Analysis Preliminary Results*, June 2009.

(continued on page 5

Dialogue

Vol. 17, No. 2 August 2009
www.usaee.org

Dialogue

Dialogue is a tri-annual publication of the United States Association for Energy Economics. Subscriptions are dependant on membership with USAEE.

Editor: Gürcan Gülen

Submissions

Articles, notices, news of chapter events and relevant energy news can be sent to the editor.

Gürcan Gülen
Center for Energy Economics
Bureau of Economic Geology
Jackson School of Geosciences
The University of Texas at Austin
gurcan.gulen@beg.utexas.edu
Fax: 713-654-5405
Tel: 713-654-5404

Contents

President's Message (*continued from page 4*)

siasm often applies to supporters of cellulosic ethanol, carbon capture and sequestration, new-generation nuclear power plants, nanotechnology, and perhaps even the "smart grid". Yet each has a role in our future, and our energy problems are complex and serious enough to make us examine every promising avenue.

My point is simply that economic analyses should evaluate Time as carefully as other tangible and intangible costs. Time factors into return, net present value, investment alternatives, and the manner in which decisions are reached about internalization of various externalities in the cause of public good.

* * *

Halfway through my term as USAEE President, let me salute the dozens of members whose hard work made the conference in San Francisco a grand success. Much remains to be done in 2009 – with potential enhancements to *Dialogue*, new focus on membership outreach and the establishment of additional chapters, and the achievement of greater recognition of IAEE as a unique organization for professional development and a source of valuable expertise. Let's keep it up!

Joe Dukert

Editor's Corner

I am happy to present another excellent issue of the *Dialogue*. There was no effort to create a common theme for this issue but we ended up with several articles that provide critical looks at renewables and carbon policies and their unintended consequences. Perhaps, this convergence of interest is not that surprising given the current environment of energy policy making on overdrive.

Paul Joskow, a long-time member of the USAEE, is the 2009 recipient of the Adelman-Frankel prize given by the USAEE. Paul was not able to be in San Francisco to receive his award in person; but he is sharing his perspectives based on 35 years of experience in an insightful article. He focuses on the role of regulation covering price, entry, environment and energy efficiency arenas. He compares the success of deregulation in the natural gas industry to disappointments of abandoned restructuring in electricity markets. Paul cautions against the simplistic belief that investors and consumers routinely leave $100 bills on the floor when it comes to energy efficiency and conservation decisions. Such beliefs support the move towards more regulation. As Paul puts it "It is hard to be convinced that Congress is likely to get it right more often than not." Finally, on energy security, I will just copy the last sentence of Paul's article: "Energy security policy rationales remain a refuge for rogues who have difficulty making more respectable and coherent cases for the policies they favor."

Next, we have two articles from researchers at the CRA International, both focusing on the American Clean Energy and Security Act of 2009, ACES or H.R. 2454 by Reps. Waxman and Markey. In the first article, Montgomery et al highlight the potential macroeconomic impacts of the bill and uncertainties with the provisions of offsets. Their model results include a GDP drop of 1.2% and a standard of living fall of $800 per average household in 2020. These costs are due to adoption of more costly methods of electricity generation, low-carbon fuels and more intensive energy conservation measures (hence higher energy prices), and opportunity cost of these investments.

In the second article, Neimeyer et al question the wisdom of having both a federal renewable electricity standard (RES) and cap & trade in H.R. 2454. Their modeling exercise shows that the national RES does not lead to more renewables than what existing state programs would encourage nor it would lead to any incremental reduction in CO_2 emissions. While yielding negligible, if any, benefits, the national RES induces significant wealth transfers from renewable resource-rich regions to resource-poor regions via trading of Renewable Energy Certificates.

Texas is leading the nation in wind capacity with more than 8 GW installed. ERCOT, the system operator in Texas, has been concerned about the increase in wind capacity for some time; and FERC has recently initiated a new study focusing on frequency response to assess reliable integration of intermittent resources such as wind. Mark B. Lively, Utility Economic Engineers, provides an analysis of reliability challenges of integrating such resources over which system operators have little control. Wind generation is highly concentrated in West Texas; transmission constraints lead to negative bidding by wind generators to collect their production tax credits and RECs. As such, overloading of the transmission remains a problem for ERCOT. Mark suggests a dynamic pricing mechanism (Wide Open Load Following) for very short time intervals to improve the reliability of the network. He provides a case study from India of how such a mechanism improved the reliability of an isolated grid.

Mark Lowry and Lullit Getachew, Pacific Economics Group argue for alternative regulation, or Altreg, in order to encourage efficient diversification by utilities as there are cross-subsidy concerns under traditional cost of service regulation. Altreg describes a general approach that weakens the link between a utility's rates and its own unit cost via a variety of mechanisms such as extending the period between rate cases through the use of automatic rate adjustment mechanisms. The authors offer statistical benchmarking to improve regulation of diversified utilities by differentiating cost factors. It seems worth considering Altreg to increase efficiency and to promote competitive markets for a variety of services.

Houston chapter of the USAEE broadcasted its April monthly meeting on the web. The secretary of the chapter, Ariana Landry, provides an informative summary of this experiment with lessons learned. This is valuable reading for officials of other chapters.

Finally, Nihan Karali provides the highlights of the 32nd IAEE International Conference hosted by the USAEE in San Francisco in June 21-24, 2009. If you were not able to attend this successful conference, you can read this article to help select which presentations to download from http://www.usaee.org/USAEE2009/program.aspx.

Enjoy the issue.

Gürcan Gülen

Do You Want to Start Your Own USAEE Chapter?

The requirements for starting a USAEE Chapter are straightforward – a viable group forms to create a Chapter and have organized to the point of adopting a set of bylaws as well as have elected a group of officers. A sample set of bylaws may be found by visiting http://www.usaee.org/startchapter.html or calling USAEE Headquarters at 216-464-2785. USAEE dues are $100.00 per person, per year for a subscription to *The USAEE Dialogue*, *The Energy Journal* and *IAEE Energy Forum*. Student membership is $40.00. USAEE bills members directly for their membership in the Association. Chapter membership must be open to all individuals whose interest is in the field of energy economics. If you have any further questions regarding the establishment of a USAEE Chapter, please do not hesitate to contact USAEE Headquarters, phone: 216-464-2785; email: usaee@usaee.org A complete Chapter start-up kit can be mailed to you.

Two great associations…one great session! All IAEE & AEA members are invited to attend the joint IAEE and AEA session to be held during the Allied Social Science Associations (ASSA) annual meeting in Atlanta, Georgia.

IAEE/AEA Session

"Climate Policy for a Post-Kyoto World"
2nd Joint IAEE/AEA Session
Meeting day/time/location to be announced

Presiding: Carlo Andrea Bollino, Dept of Economics, Finance & Stats., University of Perugia

John Weyant, Stanford University – *Global Climate Policy Scenarios: An Update*

Robert N. Stavins, John F. Kennedy School of Government, Harvard University – *Getting Serious About Global Climate Change After Copenhagen: A U.S. and International Update*

William D. Nordhaus, Department of Economics, Yale University – *The New Global Renewable Energy Policy*

Also, please visit the IAEE/USAEE Cocktail Party which will take place during the ASSA meetings. We invite you to attend this event!

The U.S. Energy Sector: Progress and Challenges, 1972-2009

*By Paul L. Joskow**

Introduction

I am honored to be the 2009 recipient of the Adelman-Frankel prize given by the United States Association for Energy Economics (USAEE). Unfortunately, I was unable to attend the annual meeting to receive this award in person. Instead, I have been invited to write this essay containing some of my reflections on changes in the energy sectors and public policies toward these sectors during my career to date. This is now a time period of over 35 years. Hard to imagine that it has been this long.

I did not start my academic career with a special interest in energy economics and policy. Of course as an undergraduate student and advisee of Alfred E. Kahn at Cornell, I could not avoid learning something about electricity pricing, the field prices of natural gas, and competition issues associated with the petroleum industry. However, as a graduate student my primary interests were in the areas of government regulation of industry, antitrust policy, political economy, the organization of firms, and industrial organization more generally. My later interests in energy grew out of my work on government regulation and industrial organization and, in turn, some of my work on government regulation and deregulation, the organization of firms, contracts, industrial organization, and environmental policy were initially stimulated by my deepening understanding of the energy sectors and the public policy environment in which they operated. Thus as my interests in energy economics and policy expanded, my research and teaching on energy economics topics have helped to reinforce and expand my broader interests in issues related to industrial organization, the organization of firms, regulation, antitrust policies, political economy and economic institutions.

Price and Entry Regulation

When I began working on energy-related topics in the early 1970s, a large fraction of the energy sector was subject to price regulation and in some sectors the government also restricted entry of new suppliers. Retail and wholesale electricity prices were regulated by state and federal regulatory agencies and electricity was supplied by regulated vertically integrated geographic monopolies. The field price of natural gas sold in interstate commerce was regulated by the Federal Power Commission (later the Federal Energy Regulatory Commission or FERC), as were prices and entry for natural gas pipeline service and contractual arrangements between interstate pipelines, gas producers, and customers (local distribution companies and large retail customers). Retail gas prices were regulated by state public utility commissions and commodity gas and transportation service at both the pipeline and local distribution levels were bundled together. The federal government began regulating oil and petroleum product prices in 1971. Coal prices were not regulated, but railroad transportation charges were heavily regulated and deficiencies in railroad price regulation and related policies affecting investment in railroad infrastructure and the quality of service adversely affected access to coal supplies. These price and entry regulations led to energy shortages, effectively subsidized energy imports, adversely affected domestic energy supplies, decreased the ability of the U.S. energy sectors to respond efficiently to supply shocks, and distorted energy consumption decisions.

Perhaps the most significant change in the U.S. energy sector since the early 1970s has been the gradual demise of price and entry regulation in most of these sectors. Petroleum prices were finally completely deregulated in the early 1980s (though lawsuits over "overcharging" during the regulated price era continued for many years). The complete deregulation of natural gas field prices took longer, but the deregulation process for commodity natural gas was finally completed in the early 1990s. The oil shock(s) of 1979-1982 led to serious domestic shortages (properly measured) of both petroleum and natural gas and complex and inefficient government administered allocation mechanisms were introduced to allocate scarce supplies. The inefficiencies of the natural gas regulatory framework were especially large and widely documented. Concerns about "windfall profits" and interregional wealth redistribution led to relatively long deregulation "transition periods," especially for natural gas.

The dramatic decline in natural gas prices (at least on the margin) that began in the mid-1980s also stimulated a completed restructuring of the rest of the natural gas industry. Long term contracts between producers and pipelines and between pipelines and local distribution companies were completely restructured and the sale of commodity gas unbundled from the sale of pipeline transportation service. In some states unbundling has been extended to the retail level as well. The Federal Energy Regulatory Commission (FERC) also adopted more "light handed" regulation of pipeline transportation charges and the hoops investors had to jump through to build new pipeline capacity were relaxed. As a result, prices for natural gas pipeline service and entry of new pipeline capacity in the U.S. have largely been deregulated "under the shadow of regulation as a backstop." I have previously referred to the current regulatory

* Paul Joskow is President, Alfred P. Sloan Foundation and Elizabeth and James Killian Professor of Economics at the Massachusetts Institute of Technology. The opinions expressed here are his own and do not reflect the views of the Alfred P. Sloan Foundation or the Massachusetts Institute of Technology.

framework for pipeline charges and entry as a system that works in practice but not in theory, since it is difficult to define a coherent theory that describes how the current pipeline regulation actually works in practice. In theory it looks quite rigid but in practice it is quite flexible. There is, of course, a danger that the deviation between the theoretical principles of pipeline regulation and how they are applied in practice can lead to unintended consequences down the road as the political winds of regulation shifts and memory fades. Overall, however, structural and regulatory reform in the natural gas sector has created a flexible efficient North American market for natural gas that is a far cry from the mess that was created by regulation during the 1970s.

In 1982, the Staggers Act led to virtually complete deregulation of railroad charges for transporting freight. While some coal suppliers have complained repeatedly about being overcharged for service after deregulation, the overall consequences of this deregulatory initiative have been very good. It has allowed the railroad industry to restructure, to operate profitably after decades of bankruptcies, to expand and modernize the railroad infrastructure and to support the transportation of growing volumes of low-sulfur coal over much longer distances than had been feasible in the past.

The hardest nut to crack has been the restructuring and deregulation of the electric power sector. Low natural gas prices during the late 1980s and the 1990s were a driving force for restructuring here. Low natural gas prices and developments in combined cycle gas generating technology (CCGT) led to a situation where the total cost of producing electricity from these new facilities was lower than the implicit price of generation service reflected in regulated prices based on the embedded costs of existing facilities (including the costs of expensive nuclear power plants entering service during the 1980s). This gap was especially large in the Northeast, portions of the Mid-west and California. Industrial customers in particular argued for “open access” and retail competition, as was emerging the natural gas sector, in order to bypass paying regulated prices in favor of buying power directly from lower cost sources. (There was and is significant hypocrisy among some segments of the large industrial customer interest group as their policy seems to be to get the lower of the regulated or competitive price --- an unsustainable policy.) At the same time, PURPA had created a growing group of independent power suppliers which had an interest in expanding their opportunities to supply electricity in competition with utility-owned generation in a wholesale a retail market.

So, the pressure was on to restructure and deregulate potentially competitive segments of the electric power industry. The restructuring and competition program for the electricity sector adopted in the UK in 1989-90 provided a model for how it could be done and also provided some examples or where care had to be taken (e.g. generator market power). This model had a big effect on the pioneering restructuring and competition model debated and implemented in California in the mid-1990s. FERC introduced new transmission access and wholesale market rules in 1996 that supported the development of a competitive electricity sector. Variants of the California/UK model were then adopted in a number of other states including New York, Massachusetts, New Jersey, Pennsylvania, Texas, Michigan, Illinois and Ohio. Indeed, by 2000 it appeared that restructuring for competition was sweeping the electric power sector in most parts of the country. Then the California electricity crisis hit, the unfortunate consequence of a sudden spike in natural gas prices, a decade of underinvestment in new generating capacity preceding restructuring, a poorly designed stranded cost recovery mechanism, a poorly designed retail transition pricing mechanism, and a poorly designed wholesale market. The resulting chaos effectively stopped and even reversed the spread of restructuring and competition in electricity to additional states.

Today we have states that have continued their commitment to the competitive model, states that are unenthusiastic and seeking ways to reverse it (usually leading to the worst of both competitive and regulated models), and states that have never departed from the traditional model of regulated vertically integrated monopoly. This situation of a very diverse industrial organization and regulatory framework for the electric power sector that is physically integrated into three AC networks is in my view inefficient, unsustainable, and will make crafting a good greenhouse gas mitigation policy for the electric power sector especially difficult.

All things considered, one cannot but be impressed with the dramatic changes that have reduced the heavy hand of price and entry regulation and increased the role of competitive markets in the U.S. energy sectors. And these developments have served the country well by getting the prices right, stimulating more efficient supplies, and providing a framework that allows the energy system to respond quickly and efficiently to major supply shocks, such as hurricane Katrina. It also seems to me that it is a sustainable change as long as the lessons learned from the 1970s and early 1980s era about the costs of heavy handed regulation are not forgotten. While we do and will hear lots of speeches from politicians complaining about rising oil, gas and electricity prices during periods of time when supplies are tight, one sees few serious efforts to reregulating prices for natural gas, petroleum, or railroad transportation. The future of electricity sector reforms remains more in doubt, however and deserves more attention by researchers.

Environmental Regulation

The first major national environmental laws were passed in the early 1970s just as I began my academic career. The energy sectors were heavily affected by these new laws since these sectors are major emitters of conventional air pollutants, water pollutants, toxic wastes, and have noticeable and often unappealing affects on land use. Their large facilities were also easy targets for regulators. New environmental statutes and new environmental regulations tightened the constraints on the energy sectors. As climate change has become a national and international issue, the energy sectors have been at the center of policy debates since the combustion of fossil fuels in the primary source of greenhouse gasses in the United States.

Accordingly, as price and entry regulation of the energy sectors has faded away, environmental regulation has gained increasing importance. Indeed, environmental policy and energy policy are now so closely related that it is almost impossible to separate them. This fusing of environmental policy and energy policy represents a gradual but overall very dramatic change for the energy sectors. Tightening environmental constraints have affected supply costs and prices, affected fuel choices, and affected technology on both the supply and demand sides of the market. These effects will only become more significant as constraints on CO_2 emissions are tightened. As time goes on, effective CO_2 mitigation policies will lead to much less use of coal compared to business as usual, more use of natural gas, more reliance on low-carbon supply technologies, innovation to reduce the costs of low-carbon technologies, and innovations to improve the end-use efficiency with which energy is used. These changes are necessitated by the simple arithmetic of the options that are likely to be available to meet the aggressive goals to reduce CO_2 emissions by up to 80% by 2050 that we see in recent legislative proposals.

In the last 15 years we have seen a major change in thinking about the regulatory mechanisms that would be used to meet environmental goals. For 25 years the major mechanism used by federal environmental regulators was what economists refer to as "command and control." Command and control regulation refers to regulations that require emissions sources to install particular abatement technologies or to meet specific emissions constraints without regard to relative costs of emissions reductions, let alone costs vs. benefits. Two decades of research demonstrated that these policies were inefficient, slowed progress in achieving environmental goals, and often simply did not meet those goals at all. Economists favored more flexible market-based mechanisms in the form of emissions taxes or cap and trade systems that placed a price on emissions and provided incentives for sources to respond to these emissions costs in the most economical ways. These mechanisms also provided dynamic incentives for technological innovations to reduce the costs of reducing emissions. For many years the use of economic mechanisms was not taken seriously by environmental regulators.

The Clean Air Act Amendments of 1990 which created a national cap and trade system for SO_2 emissions to reduce emissions in response to concerns about the damages caused by acid rain changed this situation. The SO_2 cap and trade system was successful in all important dimensions. Its success in turn stimulated the use of cap and trade mechanisms to control NO_x emissions in some regions of the country and CO_2 emissions in the European Union. Cap and trade is a key feature of the greenhouse gas legislation being considered by the U.S. Congress as this essay is written. This is indeed, a major and positive change in the approach to environmental policies affecting the energy sectors and is compatible with the earlier policies to deregulate prices and entry in most of the energy sectors.

However, I fear that the political reality is that the faith in market-based mechanisms for controlling emissions is broad but not very deep. Economists have not helped matters by getting into heated debates about whether the right mechanism is an emissions tax or a cap and trade system. This debate is like arguing about how many angels can stand on the end of a pin and provides fodder for those who would like to see no greenhouse gas mitigation policy at all. To a first approximation an emissions tax and a cap and trade system are the equivalent if they are well designed. The "simple" emissions tax with efficient recycling of revenues that some economists favor is not the kind of emissions tax we would get in reality and is little different from a cap and trade system that auctions all emissions permits (a proposal made by President Obama in January 2009 that survived political backlash for about three weeks). A CO_2 emissions tax system would have exemption, loopholes, and wealth redistribution provisions just like the rest of the tax system. The revenues are unlikely to be recycled efficiently. A cap and trade system that clearly separates the wealth redistribution issues associated with "allocation" of allowances from the efficiency effects of free emissions permit trading and abatement incentives created by the prices from trading emissions permits in a well designed trading system (no updating, no free allowances for new facilities, no confiscation of allowances for closing facilities, etc., as with SO_2) can do just as well as an emissions tax system that must respond to the same political constraints.

I would argue as well that while it appears superficially that market-based mechanisms for controlling emissions have won out over command and control, the legislation that is now being considered in Congress is far from a pure cap and trade system. Indeed, the cap and trade system included in the leading bills could turn out to be a side show to a massive introduction of more command and control regulation. Renewable energy portfolio standards, automobile, appliance and building energy efficiency regulations, subsidies for all of them, and emissions permit allocation rules that violate the principle of separating wealth distribution and efficiency consequences may seriously undermine the relevance of the market-based mechanism in the form of a cap and trade system. So, while policymakers have certainly become more receptive to market-based mechanisms that place prices on emissions, they are not sufficiently convinced that they will work to move forward without a lot of mandates and command and control regulations.

Energy Efficiency Regulation

When I began my energy economics research career in the early 1970s, one took a standard approach to thinking about and measuring energy demand and the factors that affected it. We estimated price elasticities, income elasticities, cross-elasticities, weather effects, effects of innovations in energy-using equipment, etc. Energy was thought of more or less like any other good or service, except that research recognized that consumers did not get utility from energy itself, but rather from the useful services that it provided. Consumers were free to make their consumption decisions given their preferences and budget constraints.

This "caveat emptor" situation began to change after the second oil shock as legislation and regulations began to be implemented to mandate minimum energy efficiency standards for automobiles, appliances, and buildings. They were first implemented for automobile fleets, and gradually for household and commercial appliances, and for buildings. Utilities in many states were induced to adopt energy efficiency programs to subsidize the installation of energy equipment appliances, lighting, insulation, etc. Utilities spent over $30 billion on these programs (unadjusted for inflation) between 1990 and 2007. Appliance labeling regulations were implemented to better inform consumers about the cost of operating appliances like refrigerators. Pending legislation will significantly tighten and expand these regulations in the future. And the energy efficiency of the U.S. economy has improved significantly over time, though the rate of improvement was higher during the 1970s and early 1980s when prices were rising than since the mid-1980s as these regulations began to bite.

There are classical arguments to rationalize regulations such as these. It is hard to argue with regulations that provide consumers with more and/or better information to guide wise decisions about buying and using appliances and equipment, insulating homes, and so on since information is a public good and information markets are imperfect. Another classical argument for energy efficiency regulations is that energy prices are lower than the true social cost of supplying energy due to regulations that keep prices below competitive market levels, and external costs, including energy security costs. While it would be better to get the prices right, doing so often confronts political difficulties. Efficiency standards are more popular politically than are taxes (true from poll data comparing the public's attitudes toward gasoline taxes vs. mileage standards). However, if these were the primary rationales for energy efficiency regulations one would have thought that deregulation of energy prices, tighter environmental regulation, pricing emissions, and 20 years of experience with efficient appliances and buildings would have reduced the need for regulations by reducing significantly the market imperfections that may make such regulations desirable.

But just the opposite appears to be the case. The government is placing more emphasis on mandatory efficiency standards today than in the past --- even outlawing incandescent bulbs just as we put the price of CO_2 into electricity prices. This is the case because the classical arguments outlined above are not the ones that are used by proponents to justify energy efficiency regulations. Instead, the basic argument is that consumers face numerous "barriers" to making rational long term energy-related investment and utilization decisions. When they make investment and utilization decisions they routinely leave $100 bills on the floor that are just lying there to be picked up if consumers just acted in their own self-interest. Since they do not, the government will force them to do so with mandatory minimum energy efficiency standards or straight bans on certain types of energy-using equipment.

This widely accepted perspective leads to a number of questions. First, if these decision-making imperfections are true for investments in energy-using equipment why are they not true about every other investment in the economy that involves a tradeoff between up-front costs today for benefits of some kind in the future? What is special about energy? If it is a more general problem it raises more fundamental questions about market economies. Second, are there really $100 bills lying on the ground ready to be picked up? My own research suggests that the answer is often "no." The studies upon which these numbers are based often fail to account for the real economic costs, including transactions costs (e.g., waiting at home instead of working for the installer who never shows up), of the equipment, underestimate installation and maintenance costs, and fail to account for wide variations in consumer utilization and equipment replacement behavior.

This being said, I believe that there is compelling evidence that while there may not be $100 bills lying around for everyone to pick up there are a lot of $50 bills lying around for a significant fraction of homeowners and businesses to pick up. This in turn suggests that before imposing mandatory minimum energy efficiency standards we should better understand exactly why these $50 bills are not being picked up by those who can benefit from them. This is the case because there may be better mechanisms to "nudge" (to use Sunstein and Thaler's term) consumers to do what is in their best interests than mandatory standards or bans on appliances. Yet there is surprisingly little research that has been devoted to understanding exactly what the relevant barriers are or alternative approaches to help consumers to make decisions that are supposedly in their own self-interests.

So, in forty years we have moved from leaving it to the consumer to decide how to consume energy based on standard private cost and benefit calculations to leaving these energy consumption decisions instead to Congress to decide. It is hard to be convinced that Congress is likely to get it right more often than not.

Energy Security

There is one thing that has not changed since the early 1970s. If you cannot think of a reasoned rationale for some policy based on standard economic reasoning then argue that the policy is necessary to promote "energy security." Many people then stand up and salute when "energy security" is at risk. Unfortunately, it is not clear exactly what energy security means when the term is thrown around, or that it even has a unique definition. It usually has something to do with importing oil from "unstable" areas of the world, associated concerns that the U.S. will somehow be cut off from global oil supplies, and that we will have to live through the gasoline lines, shortages, inflation, unemployment, slower productivity growth, and so on generally associated with the 1973-74 and the 1979-82 oil shocks. The energy security case for energy policy reform reached an especially low level in the last presidential campaign. President Obama argued that renewable sources like windmills would contribute to energy security. Candidate McCain argued that nuclear power would contribute to energy security. Neither argument made any sense. Windmills and nuclear power plants produce electricity. But the U.S. uses almost no oil to generate electricity. Both windmills and nuclear power plants would largely displace fuels that are securely supplied by the U.S. and Canada. Both windmills and nuclear power may be desirable for other reasons (e.g., for reducing CO_2 emissions), but certainly not for energy security purposes. Nearly 70% of the petroleum consumed in the U.S. is used in the transportation sector and if one thinks that reducing imports of oil is a good idea it is the transportation sector not the electric power sector where the action is.

Nor does the focus on "U.S. imports from unstable parts of the world" make much sense. Only about 15% of U.S. oil imports and less than 10% of U.S. oil consumption comes from the Persian Gulf. Most of the rest comes from North America, South America and West Africa. This makes perfectly good sense since there is a well integrated world oil market and the distribution of that oil from producing to consuming countries will largely reflect transportation costs. The fact that 10% of U.S. oil consumption comes from the Persian Gulf is a fact that is irrelevant for understanding the economic impact on the U.S. and other oil importing countries of a major disruption of supplies in the Persian Gulf. This is because if there is such a disruption it will affect world oil prices not just the prices charged to the U.S. from oil produced in the Persian Gulf. The U.S. could import nothing from the Persian Gulf and still face the economic consequences of a major global oil supply disruption. Moreover, the oil shortages observed in the U.S. during the first and second oil shocks were due primarily to the price regulations and administrative rationing schemes that were in pact, not because these is a necessary feature of oil supply shocks.

It is clear to me that thinking and rhetoric about energy security has not advanced very far in 35+ years. We need fresh thinking that clearly defines exactly what we mean by energy security, takes a global perspective that incorporates the attributes of world oil markets into account, and policies that are ultimately based on reducing the economic and wealth redistribution effects of oil supply shocks on the U.S. economy and those of other oil importing countries.

Conclusion

Over the last nearly four decades major progress has been made in removing costly price and entry regulations affecting almost every energy sector directly or indirectly. I consider the reforms affecting the natural gas industry to be most impressive. Those affecting the electric power sector the most disappointing. Environmental policy and regulation has replaced price and entry regulation as the most important menu of regulatory policies affecting all energy sectors. The role of environmental policy will only become greater as the U.S. becomes serious about climate change. There is much to say for the argument that policymakers have gotten religion on the importance of relying on market mechanisms for allocating scarce resources to and within the energy sector and for relying more on market-based instruments to deal with environmental problems. However, the support for markets and market-based instruments is not as strong as may first meet the eye. We can look forward to a growing role for government regulation in choosing the technologies used to produce and especially to consume energy even as policy moves forward placing prices on CO_2 emissions. Thus, in the last 35+ years we have moved from heavy handed reliance on one type of regulation of energy markets motivated by one set of economic concerns and interests to heavy reliance on another type of regulation motivated by environmental concerns. Energy security policy rationales remain a refuge for rogues who have difficulty making more respectable and coherent cases for the policies they favor.

Macroeconomic Analysis of American Clean Energy and Security Act of 2009

By Robert Baron, Paul Bernstein, Scott Bloomberg, Kenneth Ditzel, Julian Lamy, Lee Lane, David Montgomery, Anne Smith, Sugandha Tuladhar, and Mei Yuan*

Introduction

This article highlights the potential impacts of the energy and climate legislation recently released by Reps. Waxman and Markey (hereafter referred to as American Clean Energy and Security Act of 2009, ACES or H.R.2454)[1] and uncertainties with the provisions of offsets. We begin with an overview of the provisions we modeled followed by a discussion of the impacts on cost per household, gross domestic product (GDP) and job loss. Next, we describe the sensitivity analysis assumptions and discuss the uncertainties surrounding international offsets. The impacts are estimated using CRA International's MRN-NEEM integrated general equilibrium modeling framework.[2]

In analyzing ACES, we have estimated a 2020 decline in GDP (relative to what it would be without this policy) of approximately 1.2%. These costs arise because the bill's purpose of bringing emissions down from business-as-usual levels to the cap, requires adoption of more costly methods of electricity generation and investment in producing more expensive, low-carbon fuels and more intensive energy conservation measures. These actions divert resources that would otherwise be available to produce other goods and services that make up GDP into the provision of the same or lower level of energy services. The standard of living of the average household is estimated to fall by $800 in 2020, which takes into account all negative effects of ACES on the average household including higher prices for energy and other goods, lower wages and reduced hours of work, reduced returns from savings and retirement investment, and all the offsetting effects of free allowances and rebates of auction revenues on a household's disposable income.

Overview of Provisions Modeled

The text of ACES exceeds 900 pages in length. Congress is continuing to make changes in the bill, making it impossible to model the impact of some provisions. Many provisions that are provided have too little an economic impact, or their effect is too speculative, to warrant modeling. In other cases, provisions are economically consequential, but modeling them would require time and resource constraints that exceed those available for this initial effort. Detailed energy efficiency standards and mandates are consequential and are likely to raise costs and economic impacts given that they change the decisions that households and businesses would make in response to the incentives created by the cap-and-trade program. However, modeling the complete set of provisions requires a more detailed representation of individual/business decisions than any comprehensive economic model can encompass.

Thus, it is important to understand what aspects of ACES have been addressed, and what lies beyond the scope of the analysis. Table 1 summarizes the primary provisions included in this analysis.

Table 1
ACES Provisions Modeled

Provision	Details
Combined efficiency and renewable electricity standard	Required specified percentages of a baseline level of electricity sales to be met with qualified renewable resources; baseline level excludes certain existing hydroelectric generation, sales from small local distribution companies (LDCs) and generation from new nuclear and carbon capture and storage units
Greenhouse gas cap & trade	Cap on covered emissions from 2012-2050, allows banking/borrowing, annually allows for up to 2 billion in offsets (split between domestic and international offsets)
Allowances for carbon capture and storage (CCS)	Funds from allowances are used to bring online 3 GW of new CCS in 2020
Allocations provisions and revenue recycling	Regional and U.S. welfare impacts reflect ACES's provisions for free allocations to industries and for investments in CCS and adaptation. All auctioned revenues are recycled to U.S. consumers.

Results

One of the primary sections of ACES is a GHG cap-and-trade program aimed at reducing GHG emissions by 83% in 2050. This would be achieved by creating a limited supply of "allowances" required for the use of carbon-emitting energy, thereby increasing energy costs to the U.S. economy. As the cap progressively tightens with time (i.e., allowances become scarcer), the marginal source of reducing emissions becomes more expensive as lower-cost sources of emissions reductions are exhausted. As a result, the price of an allowance increases as the cap becomes more stringent.

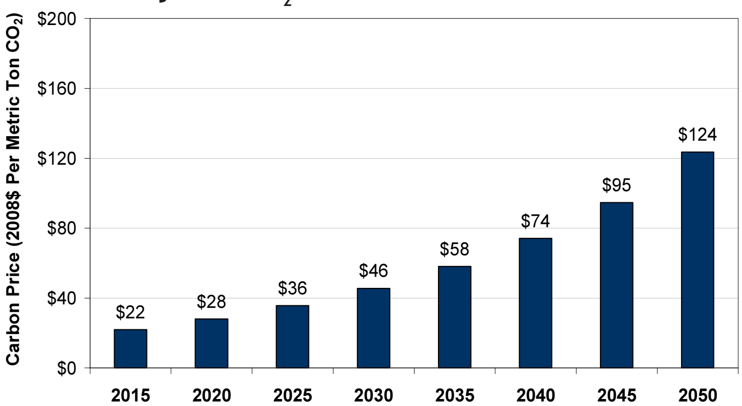
Figure 1 presents estimates of the CO_2 allowance price during the forecast period.[3] By 2020, the allow-

* Robert Baron, Paul Bernstein, Scott Bloomberg, Kenneth Ditzel, Julian Lamy, Lee Lane, David Montgomery, Anne Smith, Sugandha Tuladhar, and Mei Yuan are with CRA International (CRA). They may be reached through DMontgomery@crai.com
See footnotes at end of text.

ance price would increase to \$28 per metric ton of CO_2. By 2030, the allowance price would increase further to \$46 and, by 2050, the allowance price would reach \$124. The price pattern reflects the banking of permits that occurs in this policy. That is, permit prices increase by the annual discount rate of 5%.

The economic impacts resulting from the increasing CO_2 allowance prices cascade throughout the economy and would likely increase energy costs and decrease production and consumption across a wide array of goods and services. The size of the projected impacts varies by region but the direction does not. The projected impacts increase throughout the period analyzed (2015 through 2050) as the measures become more stringent, with the largest changes projected from 2030 to 2050.

Figure 1
Projected CO_2 Allowance Prices Due to ACES



Source: CRA Model Results, 2009

Household Purchasing Power

Higher energy costs generally mean that consumers must spend a larger percentage of their income to maintain their current level of household energy services. At the same time, significant quantities of energy are needed to produce and transport the many non-energy goods and services. The projected higher costs of these goods and services would be expected to magnify the loss in household purchasing power associated with the direct purchase of energy services. At the same time, higher energy costs across the economy as a whole would lower income. Wage rate falls as a result of lower productivity caused by the policy leading to lower income. Similarly, lower returns on investment would reduce household income from savings and retirement funds. Figure 2 shows the increasing erosion of household purchasing power that is projected as a result of ACES, due to the combination of all these factors. These estimates of changes in household purchasing power are based on the assumption that all auction revenues are returned to households on a per capita basis and that the value of allocated allowances are also returned to households in the form of utility rebates and increased investment income from companies receiving allocations.

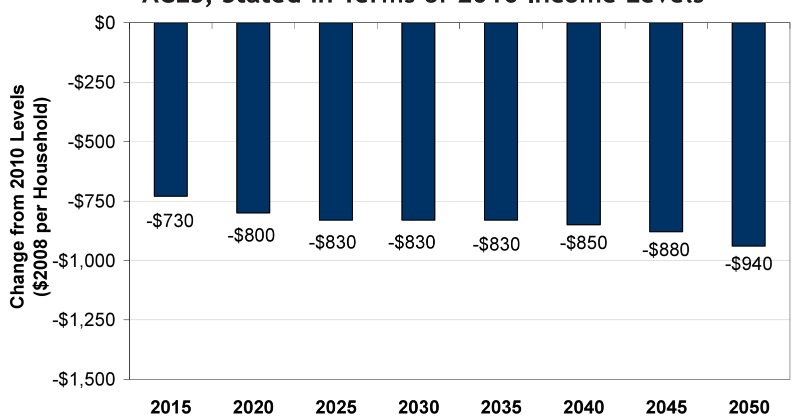
GDP

The estimated impacts on GDP would follow a similar pattern to the declines in household purchasing power. Higher production costs and lower household purchasing power interact; employment and consumption fall; and total economic activity, measured as GDP, also declines. In 2015, GDP is projected to decline by 1.0% (\$170 billion in \$2008) below the baseline level. In 2030, it is projected to decline1.3% (\$350 billion) below the baseline, reflecting the investment needed to build the infrastructure necessary to comply with future more stringent emission caps, and in 2050 the decline is 1.5% (\$730 billion). Figure 3 illustrates the pattern of estimated GDP losses through time.

Jobs

Figure 4 indicates that the projected job losses would be distributed throughout the country. Regions that experience a larger decline in employment relative to the U.S. average are the West, Oklahoma/Texas and the Mississippi Valley; regions that suffer a smaller decline than the U.S. average are the Midwest, Northeast, and California. Losses in the Great Plains, Mid-Atlantic, and the Southeast are near the national average.

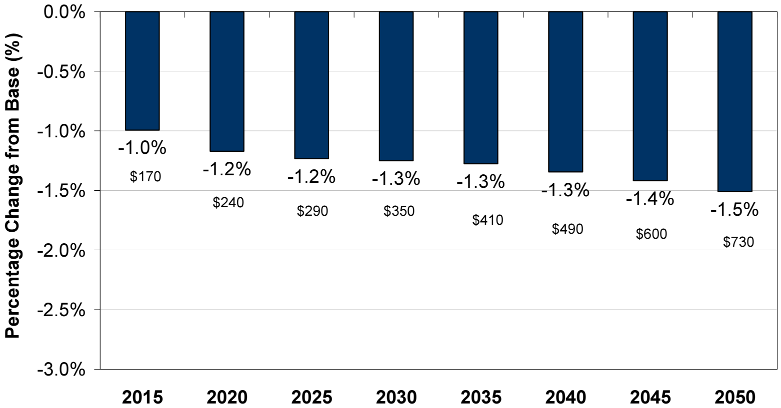
Figure 2
Projected Impact on Household Purchasing Power Due to ACES, Stated in Terms of 2010 Income Levels



Source: CRA Model Results, 2009

A region's industrial impacts, and hence employment effects, strongly correlate with the region's composition of industries and the energy-intensity of these industries. The Northeast and California fare better than other regions because of their initial economic circumstances. Namely, these regions' industries are less

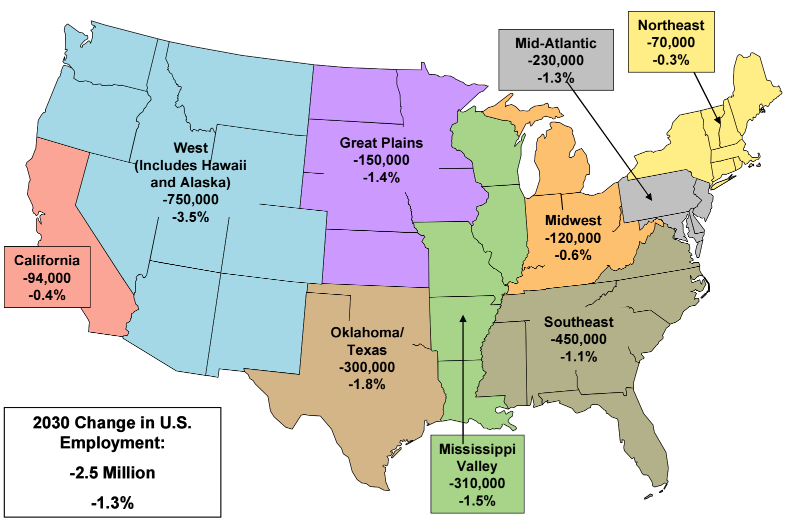
Figure 3
Projected Impact on GDP Due to ACES, Relative to the Baseline (percent and billions of $2008)



Source: CRA Model Results, 2009

energy-intensive, as is the overall composition of industry. At the other end of the spectrum are the Mississippi Valley, Oklahoma/Texas and West regions, which are more concentrated in conventional energy production activities and energy-intensive industries.

Figure 4
Projected Regional Distribution of Changes to Employment in 2030 due to ACES



Source: CRA Model Results, 2009

Sensitivity Results

To illustrate the uncertainty of outcomes from a rigid cap, we constructed a High and Low Cost case developing a range of assumptions about specific future economic and technology factors that will influence the level of carbon emissions and costs but cannot be predicted accurately in advance. Table 2 below describes the range of assumptions used to define the High and Low Cost cases, compared to Reference case assumptions.

Each of these factors represents a true uncertainty, about future growth in the economy and energy demand, about how energy use will respond to higher prices derived from the cap-and-trade system, about future developments in the performance and cost of electricity generation and transportation technologies, and about limits that may be imposed on key technologies due to regulatory action or litigation. These factors cannot be known in advance, and the assumptions chosen for the sensitivity analysis represent quite reasonable outcomes that many observers would see as likely. **Figure 5** shows the range of carbon prices that result form the Low and High Cost assumptions.

In 2015 the High Cost assumptions lead to a carbon price about 90% higher than the Reference case, a percentage difference that is maintained out to 2050 because of the assumption that banking is utilized to minimize the overall cost of the cap. The Low Cost case only leads to carbon prices a few dollars lower, suggesting that the Reference case assumptions are about as favorable a set of relevant assumptions as it is possible to make about the factors considered, given current knowledge. (Some unanticipated, major breakthrough in technology might result in a lower cost than this range, but this would require very specific technology assumptions that are simply not justifiable with any current information. Such breakthroughs are unlikely without more emphasis on game-changing R&D than is found in ACES and the stimulus package, which both concentrate on deployment of more mature technologies.)

Energy Prices

Our analysis shows that retail energy rates, exclusive of rebates and credits from allocations would be significantly higher in the policy than in the absence of ACES.[4] Relative to the baseline, retail natural gas rates would rise by an estimated 10% ($1.20 per MMBtu) in 2015, by 16% ($2.30) in 2030 and by 34% ($5.40) in 2050 (see Figure 6). Retail electricity rates are estimated to increase by 7.2% (1.1 cents per kWh) relative to baseline levels in 2015, by 21% (2.8 cents) in 2030 and by 44% (6.1 cents) in 2050 (see **Figure 7**).

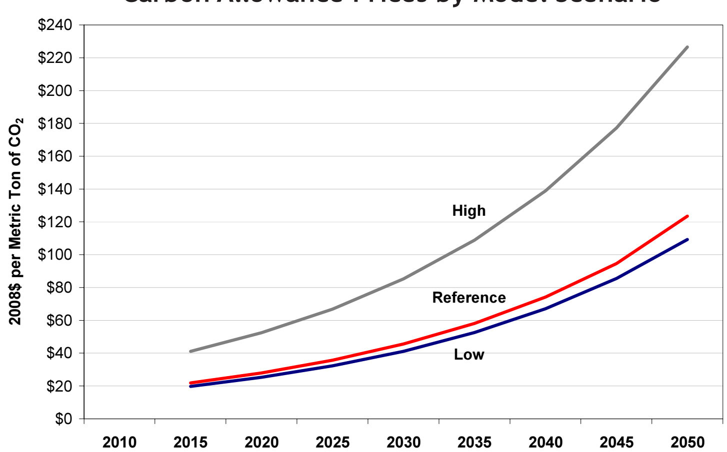
International Offsets

The cost and availability of international offsets is perhaps the most uncertain of all the factors influencing the cost of ACES. To understand how large a role international offsets play, we analyzed an alternative scenario to the Reference case in which no international offsets were allowed. This sensitivity represents the

Table 2
Range of Assumptions in Low and High Cost Cases Compared to Reference Case

	Low Cost	Reference	High Cost
Electricity Demand	AEO 2009 April Release (0.90% 2010-2030 CAGR)	AEO 2009 Early Release (1.00% 2010-2030 CAGR)	AEO 2009 Early Release + Difference b/w Early & April Release
Natural Gas Prices	Same as Reference	AEO 2009 Early Release through 2030, with a 2050 wellhead target of $9/MMBtu (in 2003$)	Same as reference
Demand Elasticity	Higher demand elasticity	CRA Standard	Lower demand elasticity
Low-Carbon Fuel Transportation Technology	Reduce zero- and low-carbon alternative fuels down to cost parity with motor gasoline	CRA Standard	Assume no zero-carbon fuel
Capital Costs for New Generating Technologies	Same as reference	AEO 2009 Early Release, save for nuclear (public filings) and geothermal (EPA NEEDS 2006)	Flat-line costs at first-year AEO 2009 Early Release
CCS Capacity Limits	270 GW by 2050	180 GW by 2050	Same as reference
Nuclear Capacity Limits	EPA W-M (266 GW by 2050)	206 GW by 2050	Allow existing nuclear fleet (103 GW) to be replaced, but no more
Offsets	Same as reference	Wealth transfers out of U.S. from international offset purchases priced at marginal cost of international offsets	Wealth transfers out of U.S. from international offset purchases priced at CO_2 allowance price, no international avoided deforestation offsets

Figure 5
Carbon Allowance Prices by Model Scenario



Source: CRA Model Results, 2009

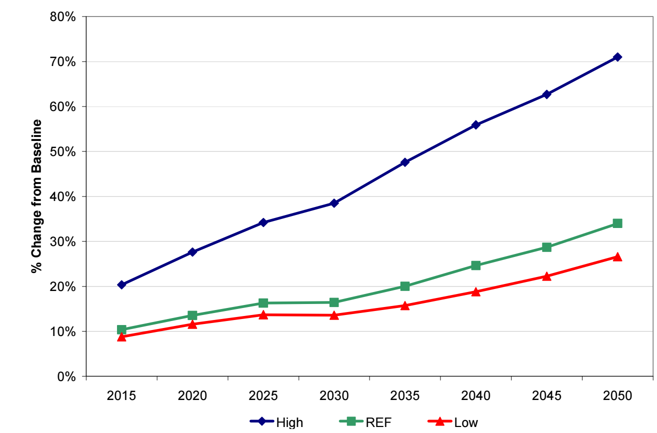
possibility that international offsets might not be available at as low a cost and in as large quantities as assumed in the reference case. Results from this scenario reveal that without the use of the international offsets allowed by the bill, carbon prices would more than double (see **Figure 8**). Such an outcome could be realized if international offsets were to not be available at as low of a cost as we have assumed and/or if they were not available in as large quantities as assumed in the Reference case.

The large quantity of international offsets is at variance with the very strong sentiment in international negotiations – and reiterated in the most recent meetings of the ad hoc working group on long term cooperation – that developed countries should achieve most of their emission reductions through domestic measures. Combined with the observed wealth transfers and desire of host countries to maximize their take, the prospect of tightening the limits on international offsets seems plausible.

EPA regulation casts another cloud over offsets as a means of keeping policy costs down. Under ACES, EPA would have a great deal of discretion to limit the effective supply of allowances. The effectiveness of measures to prevent deforestation and forest degradation are notoriously difficult to measure, and EPA may be very reluctant to (and face much external pressure not to) approve a very large share of the potential supply of these types of offsets that are assumed to be fully available in our cost analysis.

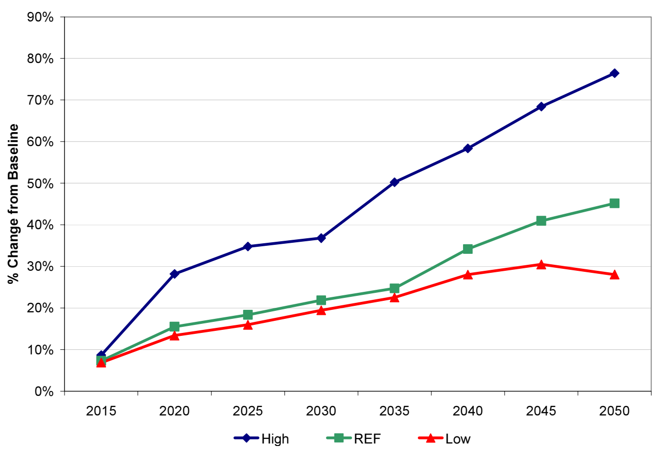
Institutions greatly compound the scientific difficulties. In many developing countries, large disparities can exist between statute books and de facto practice. These disparities can cause gaps in the system of property rights. Thus, the ownership of forest land, let alone that of any value in the carbon content of standing trees, is often unclear.[5] Since governments can find it costly to define property rights and to enforce those that it has created, the task of curtailing this resource

Figure 6
Change in Natural Gas Rates from the Baseline



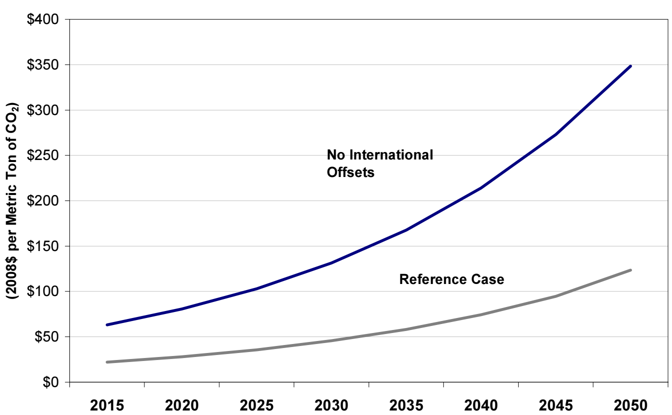
Source: CRA Model Results, 2009

Figure 7
Change in Retail Electricity Rates from the Baseline



Source: CRA Model Results, 2009

Figure 8
Comparison of Carbon Allowance Prices with and Without International Offsets



Source: CRA Model Results, 2009

over-use is intractable.[6] In such cases laws intended to establish clear property rights and curb forest decline may have little real world effect. It would, then, not be surprising for EPA to adopt a highly skeptical attitude toward claims of avoided deforestation emissions. That stance, however, could well make forestry offsets very scarce despite the large potential for emission reduction that exists in principle. If this happens, estimated costs of ACES would be greatly increased.

Footnotes

[1] Waxman, Rep. Henry and Markey, Rep. Edward, H.R.2454, "American Clean Energy and Security Act of 2009," released May 15, 2009.

[2] Tuladhar et al. 2009, Smith 2007.

[3] All allowance prices are stated in terms of 2008 dollars per metric ton of CO_2e.

[4] Allowance allocations to local distribution companies for electricity and natural gas are not intended to be used to reduce rates, but are expected to benefit ratepayers through fixed rebates and/or funding of energy efficiency projects. Higher rates create an incentive to conserve energy and subsidies on rates could mask this incentive.

[5] Cotula, L. and Mayers, J., Tenure in REDD – Start-point or afterthought?, Natural Resource Issues No. 15. International Institute for Environment and Development, London, UK, 2009.

[6] Libecap, Gary D., "Contracting for Property Rights" in Property Rights: Cooperation, Conflict and Law, Terry L. Anderson and Fred S. McChesney editors, Princeton University Press, Princeton, 2003.

References

Cotula, L. and Mayers, J., Tenure in REDD – Start-point or afterthought?, Natural Resource Issues No. 15. International Institute for Environment and Development, London, UK, 2009.

Libecap, Gary D., "Contracting for Property Rights" in Property Rights: Cooperation, Conflict and Law, Terry L. Anderson and Fred S. McChesney editors, Princeton University Press, Princeton, 2003.

Montgomery, W. David, Prepared Testimony of W.David Montgomery before the Committee on "Energy and Commerce Subcommittee on Energy and Environment U.S. House of Representatives Hearing on Allowance Allocation Policies in Climate Legislation," June 9, 2009.

Smith, A., Testimony to the Committee on Budget of the U.S. House of Representatives on "Accounting for the Fiscal Impacts of Controlling Carbon Emissions," November 1, 2007 (http://budget.house.gov/hearings/2007/11.01smith_testimony.pdf).

Tuladhar, S.D., M. Yuan, P. Bernstein, W.D. Montgomery, and A. Smith. A Top-Down Bottom-Up Modeling Approach to Climate Change Policy Analysis, Energy Economics, Forthcoming.

USAEE
United States Association for Energy Economics

The Merits of Combining a Renewable Electricity Standard with a Greenhouse Gas Cap-and-Trade Policy: An Analysis of the American Clean Energy and Security Act of 2009 (H.R.2454)

*By Michael Neimeyer, Scott Bloomberg, and Ken Ditzel**

Two of the principal goals of a renewable electricity standard (RES, sometimes referred to as a renewables portfolio standard or RPS) are to (1) spur growth in renewable forms of electricity vis a vis conventional generating technologies and (2) reduce greenhouse gas (GHG) emissions. An RES does so by requiring electricity suppliers to satisfy a certain percentage of their sales with electricity generated from qualified renewable resources. The American Clean Energy and Security Act of 2009 (hereafter referred to as H.R. 2454) released on May 15, 2009 by Reps. Waxman and Markey establishes a national RES combined with an economy-wide cap-and-trade program for GHG emissions. In this paper, CRA International (CRA) builds upon its previous analysis of H.R.2454[1] to appraise the merits of the proposed bill's national RES provisions. In particular, we find the following:

1. The national RES does not incentivize much renewable generation over and above what is motivated by existing, often more stringent state renewable portfolio standards.
2. Layering a national RES on top of a GHG cap-and-trade scheme does not result in <u>any</u> incremental reductions of CO_2 emissions. The national RES merely redistributes where in the economy emission reductions take place, mandating renewable energy over potentially less costly emission reduction opportunities in other areas.
3. The national RES induces significant transfers of wealth in the form of renewable energy credits (RECs) from renewable resource-rich regions to resource-poor regions.

Modeling Approach

Title I of H.R.2454 requires retail electric utilities to meet specified percentages of their annual retail sales through renewable electricity generation and energy efficiency savings. The combined standard is initially set to 6% of retail electricity sales in 2012 and rises to a maximum of 20% by 2020, as given below in Table 1. Up to one-quarter of the requirement can be met with savings from energy efficiency, and state governors can petition to increase the proportion of compliance met through energy efficiency to up to two-fifths of the combined percentage requirement. In all modeled scenarios described in this paper, CRA assumes that this 25% energy efficiency carve-out is fully utilized in every year, such that, in 2020, the effective renewable electricity requirement is 15%.[2] As an alternative to procuring RECs, which represent the renewable attributes of a megawatt-hour (MWh) of renewable generation, retail electric utilities can make a $25 per MWh (in 2009 dollars, subsequently adjusted for inflation) alternative compliance payment (ACP), the funds from which will flow back to state-led research and development of renewable electricity generation technologies and cost-effective energy efficiency programs.

Table 1
Percentage Requirements of the Combined Electrical Efficiency and Renewable Electricity Standard in H.R.2454 and in CRA Modeled Scenarios.

Year	% Requirement of Combined Standard	% Requirement Including Energy Efficiency Carve-Out
2012-2013	6.0%	4.5%
2014-2015	9.5%	7.1%
2016-2017	13.0%	9.8%
2018-2019	16.5%	12.4%
2020-2039	20.0%	15.0%

The percentage requirement is applied to a base amount defined to be total sales less sales from non-qualified hydroelectric power and municipal solid waste. Also, smaller retail electricity suppliers with sales less than four million MWh per year are not required to comply. The types of renewable resources that are eligible to meet the requirements include wind energy, solar energy, geothermal energy, biomass/landfill gas, qualified hydropower, and marine/hydrokinetic renewable energy. In addition, as new nuclear units and units with carbon capture and storage (CCS) are built, their generation is subtracted from the base amount.

In order to ascertain the incremental effects of the national RES in worlds with and without a national GHG cap-and-trade scheme, this paper evaluates the following four cases:

1. A no-federal policy baseline featuring all existing state RPS programs (hereafter referred to as the BAU, or business-as-usual, case);
2. The BAU with the national RES (national RES only);
3. H.R.2454 without the national RES (cap-and-trade only);
4. H.R.2454 with the national RES (full H.R.2454).

Any proper appraisal of the above scenarios requires a modeling suite capable of simulating (1) unit-level electric sector dispatch and environmental compliance, and (2) the operations of the major features of the U.S economy, including the many pathways through which legislation like federal cap-and-trade can ripple through to various economic sectors and activities. This paper

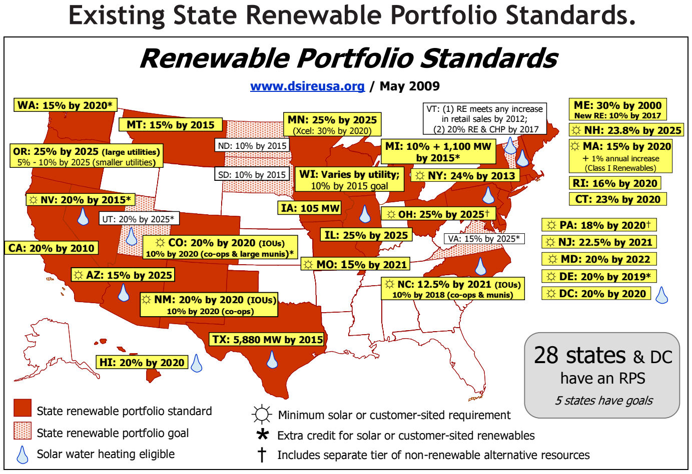
* Michael Neimeyer, Scott Bloomberg, and Ken Ditzel are with CRA International, Washington, D.C.
See footnotes at end of text.

employs CRA's proprietary, state-of-the-art MRN-NEEM modeling system to analyze the potential impacts from H.R.2454 and, in particular, the national RES. A more complete documentation of the MRN-NEEM model is available on CRA's website.[3]

Overview of Existing Renewable Portfolio Standards

There are currently twenty-eight states in addition to the District of Columbia that have passed mandatory renewable portfolio standards, in addition to five states that have established non-binding goals. Although all renewable portfolio standards share a common goal of increasing renewable generation through a market-based mechanism, each state RPS is characterized differently in terms of (1) what technologies and plant vintages are considered eligible, (2) the percentage generation or capacity requirements from renewable resources over time, (3) any special treatment of individual technologies, (4) the existence and level of an ACP mechanism in lieu of procuring RECs, and (5) credit multipliers for resources of certain types or within certain geographies. Figure 1 below provides a comprehensive, high-level summary of the thirty-four RPS requirements and goals currently in place, and sheds light on two important themes.[4] First, judging by the long term percentage requirements, there are many states pursuing more aggressive RPS programs than what H.R.2454 is mandating nationally. Notwithstanding the fact that some states espouse cost-containment provisions that would strip back RPS requirements if the state economy were too adversely affected, this trend suggests that there will be many regions that will readily exceed the RPS requirements in H.R.2454 if it were to become law. Second, the strictest RPS requirements tend to reside in regions with superior access to low-cost renewable resources (*e.g.*, Minnesota with abundant wind resources). Conversely, the lack of a state RPS, as is the case throughout much of the Southeast, reflects a relative scarcity of low-cost renewable generation opportunities.

Figure 1
Existing State Renewable Portfolio Standards.

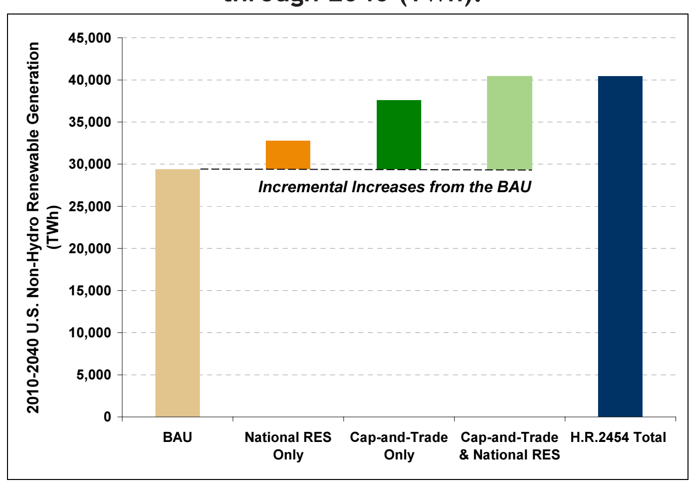


Modeling Results and Analysis

Renewable Generation

The national RES incentivizes little incremental renewable generation in excess of that induced by state RPS programs. Figure 2 presents total non-hydro renewable generation (in terawatt-hours, or TWh) from the start of the modeling horizon, 2010, through the year immediately following the end of the policy, 2040, across the four modeled scenarios. The national RES, when not paired with cap-and-trade, precipitates only 11% more renewable generation than what would be seen without enactment of any part of H.R.2454. This result is largely attributable to the breadth and stringency of the twenty-nine existing RPS programs. These existing RPS programs will, even in the absence of federal legislation, elicit nearly sufficient renewable generation to meet a national RES. As will be described later, the regional disposition of REC supplies under a national cap will have important implications for where compliance costs will be incurred. Electricity suppliers in regions that enjoy superior access to cheap renewable resources (and that often feature the most aggressive RPS requirements) stand to profit by selling excess national RECs to suppliers in regions with limited access to cheap renewable resources. Indeed, an often overlooked characteristic of a state-by-state approach to RPS requirements relates to how such an approach tends to avoid welfare distributions across states, even though it may not equalize the marginal cost of renewable generation across the country, as a national RES with tradable RECs would do.

Figure 2
U.S. Non-Hydro Renewable Generation from 2010 through 2040 (TWh).



Layering the national RES on top of the H.R.2454 GHG cap-and-trade program accomplishes comparably small expansions in renewable generation over the policy horizon. Figure 2 clearly shows that cap-and-trade in and of itself is far more effective in driving growth in renewable electricity, accounting for a 28% increase over the BAU case. (Note that, while the full H.R.2454 case (cap-and-trade & national RES) does offer approximately 2,800 TWh more renewable generation, this amount constitutes only an 8% increase over the cap-and-trade only case.) This outcome is all the more noteworthy given that the cap-and-trade program will invariably reduce electricity consumption and, in turn, the base amount against which the national percentage requirements are applied. Thus, as a percentage of total electricity generation, the increase in renewable generation in the cap-and-trade only case is even larger.

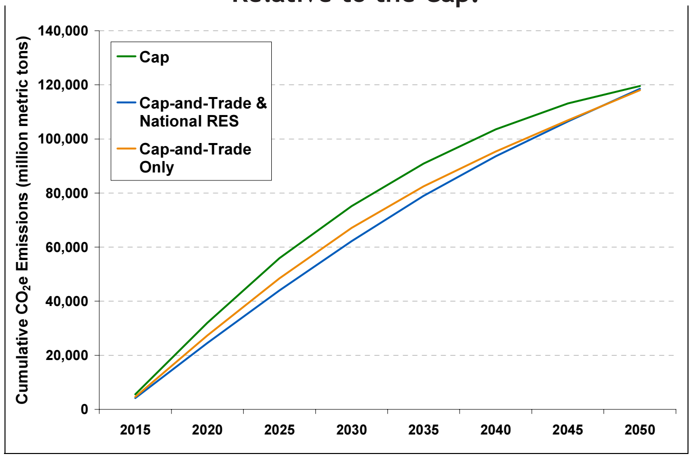
Cap-and-trade programs encourage all forms of low-carbon electricity generation by putting a cost on CO_2 emissions from conventional generators burning fossil fuels. In such fashion, cap-and-trade programs avoid picking winners, or certain low-carbon generating technologies over others (conversely, the national RES, in its prescription of qualifying renewable technologies, does pick winners, and, as will be detailed later, this can increase overall policy costs). With a zero carbon footprint, renewable technologies will feature prominently in the generation mix under cap-and-trade alone, along with other technologies like nuclear and CCS. Indeed, given how the addition of the national RES to the GHG cap-and-trade program achieves only 8% more renewable generation, the national RES appears to be redundant in terms of facilitating the advancement of renewable electricity.

CO_2 Emissions

What about another one of the chief aims of the national RES: lowering CO_2 emissions? Packaging a national RES with the GHG cap-and-trade program does not reduce one additional ton of U.S. CO_2 emissions above and beyond that required to comply with the GHG cap-and-trade program. The cap on CO_2 emissions is the binding constraint, and sets the trajectory for emission reductions from the U.S. economy. The addition of the national RES to a GHG cap-and-trade program might change where emission reductions are taking place in the economy, but does not affect the amount of emission reductions. Figure 3 corroborates that cumulative CO_2 emissions in the cap-and-trade only and full H.R.2454 cases are virtually indistinguishable, and, of note, end up at the level prescribed by the 2012 through 2050 GHG caps enumerated in H.R.2454.

The national RES mandates are likely to be more expensive emission reductions in the form of wind, biomass, solar, *etc.* in lieu of letting the market choose the lowest cost options. The rationale of cap-and-trade is to entrust the market, as opposed to the government's best guesses, to select the most cost-effective means of reducing GHG emissions. In fact, our modeling shows that the GHG cap-and-trade program induces enough renewable generation to render the national RES non-binding in all but ten years (2020 through 2029) in the full H.R.2454 case. In the non-binding years, the national RES mandate has no effect on emissions whatsoever, yet would

Figure 3
Cumulative U.S. CO_2 Equivalent Emissions in the Cap-and-Trade Only and Full H.R.2454 Cases Relative to the Cap.



needlessly carry all the costs of monitoring, measurement, enforcement, and compliance contingent with the administration of a national standard. From 2020 through 2029 when the national RES is binding, there are two possible scenarios. The first, and unlikely best-case, scenario is one in which the government omnisciently chooses renewable technologies that would have been motivated by cap-and-trade anyway, in which case only the aforementioned administrative costs would have to be borne by American consumers. The second, and more likely, scenario is that the mandate would compel industry to pursue renewable generation options in place of more cost-effective emission reductions in other areas of the economy.

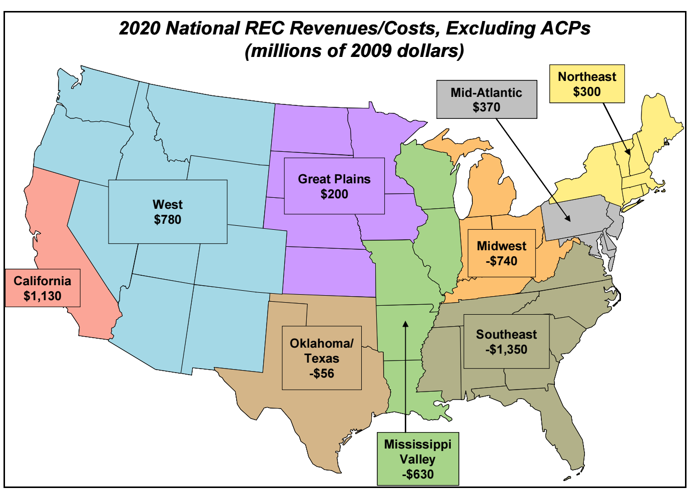
As an illustrative example, suppose that the economy has two potential sources for emissions reductions, any of which alone can achieve the 10 million metric tons of CO_2 emission reductions necessary to meet a cap: (1) replacing a natural gas-fired plant with a solar-powered photovoltaic (PV) array, with promised CO_2 emission reductions of 12 million metric tons, or (2) modifying a natural gas fired plant with a CCS retrofit, with promised emission reductions of 10 million metric tons. Suppose, further, that the solar option has a higher abatement cost than the sequestration retrofit option, but achieves the previously described greater reduction in CO_2 emissions. In the cap-and-trade only case, the market would select the sequestration retrofit option as the most cost-effective way to garner the 10 million metric tons of emission reductions necessary to meet the GHG cap. On the other hand, in the full H.R.2454 case, the national RES mandate might necessitate the more costly solar PV project in place of the sequestration retrofit, which would deliver 2 million metric tons of emission reductions over and above the cap. However, since the cap is the binding constraint which places a value on CO_2 emission reductions, the extra 2 million metric tons of reductions would necessarily be offset by fewer reductions in some other sector of the economy. In either scenario (with or without the national RES), the cap remains the same, and the overall pattern of CO_2 emissions is identical.

Regional Wealth Transfers

The national RES creates significant transfers of wealth, in the form of REC transactions, from resource-poor regions to resource-rich regions. The standard creates a national market in which electricity suppliers from across the nation buy and sell RECs to comply with annual requirements. By design, this system creates regional winners and losers. Utilities with superior access to relatively cheap, abundant renewable resources stand to profit from exceeding their requirement and selling these surplus renewable attributes to regions deficient in low-cost renewable resources. In addition, the coexistence of stringent state RPS requirements in resource-rich regions like the Northwest and the Great Plains crowds out much of the remaining inframarginal renewable resources. (H.R.2454 allows a megawatt-hour of renewable generation to, in effect, count twice, once towards any germane state RPS and again towards the national RES.) The fact that so much of the supply curve for national RECs is comprised by state RPS-induced renewable projects in resource-rich regions further disadvantages electricity suppliers in resource-poor regions.

Figure 4 presents the revenues and costs associated with transactions of national RECs across nine broad geographical regions of the U.S. economy in 2020, one of the years in which the national RES policy is binding in the full H.R.2454 case. Of note, this figure does not encompass the nearly $1.8 billion (in 2009 dollars) of ACPs, which electricity suppliers choose to submit to the federal government in order to satisfy some portion of their requirement. Most striking, though, are the wealth transfers out of the Southeast, Midwest, and Mississippi Valley. In 2020 alone, these three regions together incur

Figure 4
National REC Revenues/Costs Excluding ACPs across U.S. Regions in 2020 (Millions of 2009 Dollars)



REC transfers to other regions in excess of $2.7 billion, on top of making ACPs to the federal government of over $1.5 billion. These regions, incidentally, are also among the poorest in terms of per-capita income.

Conclusion

The national RES encumbers renewable resource-poor regions with significant additional costs in the form of REC payments. Further, in picking winners in the renewable electricity generation sector, the national RES limits the market's ability to assess the most cost-effective sources of emission reductions from across the U.S. economy. This results in charging American consumers with at least the cost of administering a largely redundant national RES program, and most likely the costs of more expensive emission reductions than would have otherwise been chosen under cap-and-trade alone. Finally, the national RES neither elicits significant increases in renewable generation nor lowers the trajectory of CO_2 emissions. If reducing carbon emissions is one of the chief motivations for a national RES, a market-based cap-and-trade approach alone does a far better job than any scheme involving the national RES proposed in H.R.2454.

Works Cited

CRA International (2009). CRA International's MRN-NEEM Integrated Model for Analysis of U.S. Greenhouse Gas Policies. Available at http://www.crai.com/uploadedFiles/RELATING_MATERIALS/Publications/BC/Energy_and_Environment/files/MRN-NEEM%20Integrated%20Model%20for%20Analysis%20of%20US%20Greenhouse%20Gas%20Policies.pdf.

CRA International (2009). Impact on the Economy of the American Clean Energy and Security Act of 2009 (H.R.2454). Prepared for the National Black Chamber of Commerce. Available at http://www.nationalbcc.org/images/stories/documents/CRA_Waxman-Markey_%205-20-09_v8.pdf.

Footnotes

[1] CRA International (2009). Impact on the Economy of the American Clean Energy and Security Act of 2009 (H.R.2454). Prepared for the National Black Chamber of Commerce. Available at http://www.nationalbcc.org/images/stories/documents/CRA_Waxman-Markey_%205-20-09_v8.pdf.

[2] It is very likely that the GHG cap-and-trade program of H.R.2454 will, distinct from the combined electrical efficiency and renewable electricity standard, produce electricity savings in excess of the maximum allowable efficiency allotments in the combined standard. In a scenario without cap-and-trade, it is less likely that investments in electrical efficiency will be more cost-effective than investments in renewable generation, and, in turn, that the full efficiency carve-out will be realized. However, in order to facilitate comparisons between scenarios with and without the national RES, CRA assumed that full efficiency allotment (*e.g.*, 5% in 2020) would be achieved throughout the policy horizon in all cases.

[3] CRA International (2009). CRA International's MRN-NEEM Integrated Model for Analysis of U.S. Greenhouse Gas Policies. Available at http://www.crai.com/uploadedFiles/RELATING_MATERIALS/Publications/BC/Energy_and_Environment/files/MRN-NEEM%20Integrated%20Model%20for%20Analysis%20of%20US%20Greenhouse%20Gas%20Policies.pdf.

[4] This map is available at http://www.dsireusa.org/documents/SummaryMaps/RPS_map.ppt.

Renewable Electric Power—Too Much of a Good Thing: Looking At ERCOT

*By Mark B. Lively**

The rapid growth in wind, solar, and other forms of renewable energy has raised the possibility that there may be too much of a good thing. In that regard, the good thing should be considered to be too much electricity, even though the newly excessive amounts of electricity might be driven by the growth in renewable energy. Generically, the issue is the growth in energy sources over which system operators have little control, sometimes including the ramp rates of generators nominally under the control of system operators.

In reaction to electricity surpluses, some system operators have begun to issue orders to renewable resources to reduce the amount of electricity that they are producing. I believe that a better course of action is to allow the market to set prices that encourage participants, whether generators or consumers, to make their own operating decisions. This avoids the potential embarrassment of turning down a free lunch in the form of renewable resources that have zero operating costs. However, when the system does have an embarrassment of riches in having too much electricity, the result sometimes has been negative prices.

ERCOT and other independent system operators (ISOs) operate bidding systems to create a forwards market for electricity. The forwards markets are typically for the next hour or might be for a sub-hour period such as the 15 minute periods used by ERCOT. Shortly before the delivery period begins, the clearing price is announced. These forwards bidding systems should be supplemented by true spot market that addresses even shorter periods of time, a concept I call WOLF for Wide Open Load Following.

The true spot market would cash out any variances from the power levels associated with the winning bids that led to the announced market clearing price. Such a true spot market could provide prices that vary every minute, or even within a minute, improving the grid discipline in relation to ramping rates within the bidding period. The WOLF pricing mechanism is presented in the paper. India has implemented a frequency driven approach to its spot market, which improved the electric grid discipline in India. A true spot market would provide better incentives for the installation of storage and load management systems.

ERCOT April 2009

The Electricity Reliability Council of Texas (ERCOT) operates the grid spanning much of Texas, a grid that operates synchronously internally but asynchronously to the other parts of the North American electric grid. The ERCOT grid has four market areas, North, South, West, and Houston. Most of the renewable resources are in the West market area. Within these market areas there is a Market Clearing Price for Energy (MCPE) that is determined every quarter hour. Thus, in April 2009, there were 2,880 MCPE for each of the market areas.

ERCOT operates a bidding program to produce the MCPE. Generators offer to provide specific amounts of electricity at given prices. ERCOT accumulates enough of the offers for each bidding period to meet the anticipated load during that bidding period. The highest price of the accepted bids becomes the MCPE.

The four market areas experience some transmission limitations between and among themselves. Sometimes these transmission limitations bind the system, in that a surplus in a low cost portion of ERCOT cannot be used fully to meet the demands in other higher cost portions of ERCOT. The wind surplus in the West market area is delivered to the other market areas across the ERCOT transmission lines. The capability of these transmission lines to deliver power reliably to the other market areas is determined by the n-1 thermal limit of the lines.[1,2]

Until recently, ERCOT system operators would order wind generators in West Texas to reduce generation when their production levels would otherwise violate the n-1 thermal limits of the lines from the West market area to the rest of ERCOT. The wind generators were unhappy with the thoughts of such rationing and asked ERCOT to develop another approach.[3,4]

ERCOT now addresses the surplus of electric power by allowing participating generators to bid negative prices for the right to sell electricity to the grid. Under the concept of negative prices, a generator pays ERCOT to take any electricity that is generated. In many respects a negative price for electricity is similar to a tipping fee charged by an incinerator. An incinerator uses trash and other combustibles to produce steam which is used to make electricity. Sometimes the incinerator buys fuel to run its boilers. Sometimes the incinerator charges for fuel delivered to the incinerator in the form of trash. Similarly, ERCOT sometimes has negative prices and charges for the right to dump electricity into ERCOT.

Table 1 shows the distribution of ERCOT MCPE during April 2009. Each row presents the number of quarter hour periods when the price was within each range. For instance, the third row is for prices between $10/MWH and $20/MWH.

The more interesting data in Table 1 are for the first row, where the prices are all negative. The high number of hours in the West market area reflects the huge surplus of wind generation in the West when it swamps the transmission system's ability to delivery electricity to the rest of ERCOT. That the other market areas have negative prices is indicative of the high cost of dynami-

* Mark B. Lively is with Utility Economic Engineers, Gaithersburg, MD. He may be reached at MbeLively@aol.com
See footnotes at end of text.

Table 1
Market Clearing Price for Energy ($/MHW), Distribution by Quarter Hour, ERCOT—April 2009

Price Limits Lower	Upper	North	South	West	Houston
-$40.00	$0.00	28	21	664	21
$0.00	$10.00	45	80	41	65
$10.00	$20.00	1261	1285	997	1258
$20.00	$30.00	1080	1064	777	1076
$30.00	$40.00	397	366	336	393
$40.00	More	69	64	65	67

cally changing production levels. For these pricing periods generators would rather incur fuel costs and be charged for dumping electricity instead of incurring the operating inefficiencies associated with ramping production down and then back up.

Table 2
Interaction of Transmission Constraints and Negative Prices, Count of Quarter Hour Periods, ERCOT April 2009

Negative Prices	Periods During Month	Price Inequalities Some	None
Periods with some negative MPCE	664	643	21
Periods with no negative MPCE	2,216	102	2,114
Totals	2,880	745	2,135

Table 2 presents the interaction of Transmission Constraints and Negative Prices on ERCOT MCPE in April 2009.

- Table 2 reports that 664 quarter hour periods had negative prices in one or more market areas. Thus, the other market areas had negative prices only when the West market area also had negative prices.
- Of those 664 quarter hour periods, 21 quarter hour periods had prices that were equal across all four zones. Thus, the 21 quarter hour periods when the prices in Houston or the North were negative were also the 21 quarter hour periods when all four market areas had negative prices. This represents 3.16% of the 664 quarter hour periods with negative prices.
- In contrast, of the 2,216 quarter hour periods when there were no negative prices, during 2,114 of these periods the prices were equal across all four market areas. During the other 102 of these periods the prices are not equal across all four market areas. These 102 periods represent 4.60% of the 2,216 periods with uniformly positive prices.

Thus, as a generality, when prices are not negative, the transmission system is not binding and prices are equal 95.40% of the time. Conversely, again as a generality, when there are negative prices, the transmission system is binding and prices are unequal across the four market areas 96.84% of the time.

Waste incinerators can charge a tipping fee for garbage because the trash haulers would otherwise have to pay a similar tipping fee at a landfill. Also, trash haulers, who have to pay the tipping fee, have other sources of revenue in the form of their charges for trash collection. Similarly, ERCOT can set negative prices for electricity, effectively charging a tipping fee, because the generators have no alternative; and, generators are willing to produce electricity for a negative price because they have other sources of revenue that are contingent on the generators being able to dump their electricity.

Generally wind generators receive a subsidy for every MWH they deliver to the grid. The subsidies form an additional revenue stream for the wind energy generators.

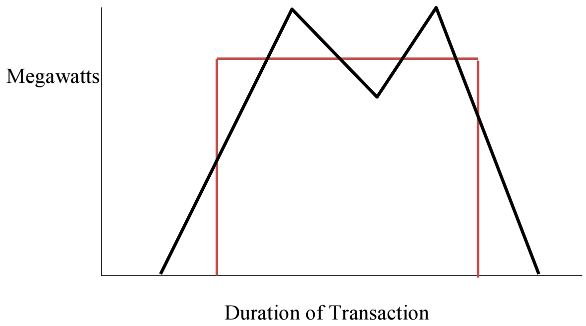
- The federal government offers tax credits for renewable electricity generation. Though the generator may be willing to pay for the right to dump electricity into the grid, the generator certainly does not want to pay more for that ability than the generator is getting in tax credits.
- Many states have created the concept of Renewable Portfolio Standards (RPS). Under an RPS, utilities and other load serving entities have to generate a stated percentage of their electricity from renewable resources. The RPS can be also be met by buying Renewable Energy Credits (REC), where the REC is separated from the physical flow of the electricity. There is a growing market for RECs, which provide an incentive for renewable generators to pay for the right to dump their electricity onto the grid.

The negative prices in the West market area show how ERCOT has been able to benefit by the competition among renewable resources in a restricted market. These renewable resources have other sources of revenue and thus can view the negative ERCOT prices as dumping fees.

Supplementing a Bidding System with a Spot Market

Most ISOs have dispatch programs that set the price for electricity during an upcoming pricing period, such as the next hour or the next quarter hour. Nominally the bids are for blocks of energy, a specific power level for the duration of the pricing period, as is suggested in the rectangular block shown in Figure 1. Though some generators will provide such a rectangular block of energy in response to winning the auction, some will provide a profile that looks much different, such as the erose shape also shown in Figure 1. The erose shape shows that the generation ramps up before the pricing period begins and fails to meet the bid amount until substantially into the pricing period. There is an overshoot and some ringing in the delivery, and finally a ramping down that begins during the pricing period and ends after the pricing period is over. Whether an erose shape is good

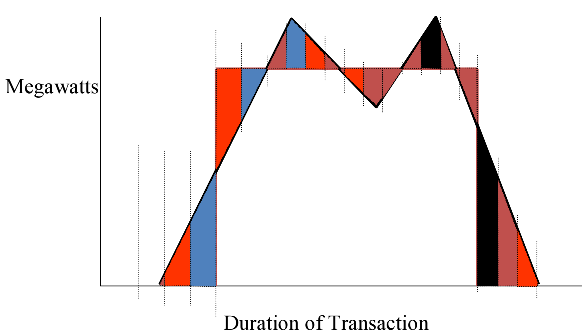
Figure 1
Scheduled vs. Delivered Power



or bad depends on what is happening with the rest of the system.

The variance between the scheduled rectangular block and the erose delivery can be handled in several ways. Many ISOs have decided not to differentiate between scheduled delivery and actual delivery, pricing everything below the erose delivery curve at a unitary price, such as the MCPE of ERCOT. Some utilities take a penalty approach, where under-deliveries are charged at 125% of the MCPE and over-deliveries are paid at only 75% of the MCPE. In the vernacular of my childhood, this approach is "Heads I win, Tails you lose." A third approach, shown in Figure 2, is to divide the delivery period into even smaller time divisions and price the unscheduled flows in each of those time divisions using a systemic price that reflects market conditions during each of the small time divisions.

Figure 2
Pricing Unscheduled Power Dynamically



I have long said that unscheduled flows of electricity during those small time divisions can be priced using a formula whose independent variables are the operating metrics of the network. For strongly connected systems, the operating metric is Area Control Error (ACE).[5] Less strongly connected systems need to include the operating metric of transmission loading, especially violations of any reliability limits. For instance, sometimes the negative prices in ERCOT's West market area are not low enough, such that there is still too much wind and the transmission lines are loaded beyond the n-1 thermal limit. In such cases, the price for the unscheduled deliveries needs to be even lower in West Texas and higher in the rest of ERCOT. Such prices will reward some participants and punish other participants.

Table 3
Varying Impact of Shortage on Generators when the MCPE is Positive

Under-Delivery	MW	Price	Payment	Average
Schedule	100	$50	$5,000	
Difference	-60	$600	$(36,000)	
Actual	40		$(31,000)	($775.00)
Over-Delivery	MW	Price	Payment	Average
Schedule	100	$50	$5,000	
Difference	50	$600	$30,000	
Actual	150		$35,000	$233.33
Combined	MW	Price	Payment	Average
Schedule	200	$50	$10,000	
Difference	-10	$600	$(6,000)	
Actual	190		$4,000	$21.05

It seems incongruous that a single price can be considered to reward some participants and punish other participants. The issue should be viewed in relation to how the participants are operating relative to the bid they entered into the dispatch process. A low price will reward those who produce less than the power level included in their bids, while a high price will reward those who produce more than the power level included in their bids. Conversely, a low price will effectively punish those who produce more than the power level included in their bid while a high price will effectively punish those who produce less than the power level included in their bids. This is shown in Table 3 for the situation of positive prices during a period of unexpected shortage.

The two situations in Table 3 are for generators who each bid to deliver 100 MW of power when the MCPE is $50/MWH. However, during the delivery period there is an overall shortage of electricity, driving up the price for unscheduled electricity to $600/MWH. Each generator gets paid $5,000/hour for the 100 MW that was included in the accepted bid. The higher price for unscheduled deliveries shows the penalty and reward effects of under-delivery versus over-delivery. Under-delivery results in a penalty where the average price is a negative $775.00/MWH while over-delivery results in a reward where the average price is now $233.33/MWH. Since the sum of the two generators shows a reduction in the actual generation relative to the scheduled generation, the total average price is lower than the $50.00/MWH MCPE.

Creating a Spot Market

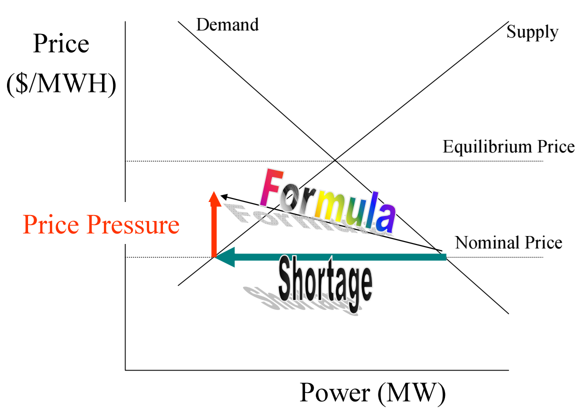
A spot market has been described as one where the goods are delivered out of inventory, without a chance to change the production process. For electricity, this definition of a spot market would need to be for very short periods of time, since the production process is constantly being changed and there is no effective inventory. Thus, a pricing plan for unscheduled flows of electricity might be considered to be a spot market.

The traditional supply and demand curve is shown in Figure 3, which includes the equilibrium price where the curves intersect with each other. The horizontal axis is power, whether the amount generated or the amount consumed. The concept is used in the bidding processes for most ISOs. The bidding process is for a future period, such as the next hour or the next quarter hour in the case of ERCOT.

But during the delivery period associated with the bidding process, the instantaneous nature of electricity provides new supply and demand curves. The actual demands and supplies are not individually nor completely measured. The system operators instead measure the gap between supply and demand, which is the previously identified Area Control Error (ACE). When ACE is calculated for an entire interconnected electrical system, the concept of ACE reduces to frequency error, the difference between standard frequency and actual frequency. Many systems calculate ACE from measurements and schedules every three to four seconds. When I requested frequency data from Chile, I received data summaries that suggested Chile measures system frequency about five times a second, many times faster than US utilities calculate ACE.

Figure 3 is supplemented by a horizontal arrow showing a Shortage. The direction of the arrow provides an indication as to whether the nominal price is too high or too low. In the case of Figure 3, the negative ACE is a shortage, suggesting that the nominal price is too low, that the equilibrium price is actually above the nominal price. The magnitude of the vertical arrow suggests how far the equilibrium price is from the nominal price. The result of repeated application of the process will provide better information as to how much the price should change for a specific ACE.

Figure 3
Wide Open Load Following Dynamic Economic Theory



Applying the concept in Figure 3 to the terminology presented above for ERCOT, the nominal price is MCPE. ACE is the frequency error, since ERCOT has no inadvertent interchange with the rest of the grid. If ERCOT has as sophisticated frequency measurements as is suggested by the data I got from Chile, ERCOT could price generation variances several times a second, though a practical number might be once a minute. This analysis is applicable when the ERCOT transmission system is unconstrained. When the ERCOT transmission system is constrained, the driver of the ACE pricing concept would include the loading on the transmission system.

Getting the Spot Price Right

Figure 3 shows that the price adjustment can be calculated as a function of the size of the imbalance between supply and demand. Typically the imbalance between supply and demand would be indicated by ACE or by frequency error in the case of a pricing area that is not interconnected with other areas. For a system such as the ERCOT West market area, the critical imbalance is the loading on the transmission system with the rest of ERCOT. When those lines are loaded beyond the limit identified by the n-1 planning process, then the spot prices should change dramatically from the MCPE since the reliability of the network is being compromised. In the West, the spot prices would be lower than the MCPE. In the rest of ERCOT, the spot prices would be higher than the MCPE.

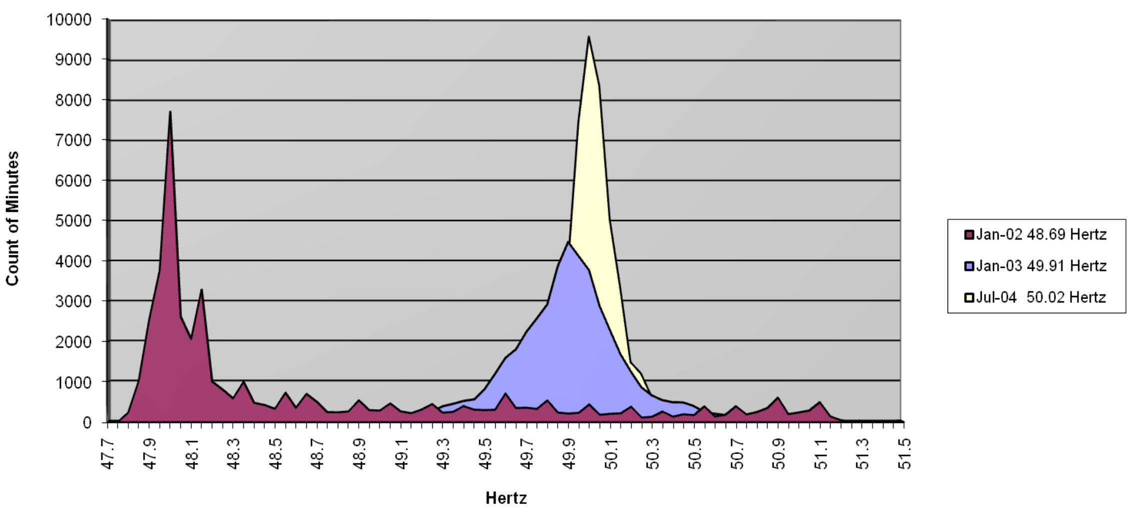
A price created by the WOLF concept is a *de facto* short run marginal cost. To the extent that generators can anticipate the WOLF price, they will optimize their production by moving their generation toward a marginal cost equal to the WOLF price. If the generator achieves full movement toward the WOLF price, the generator will be paid a price, the WOLF price, equal to the generator's marginal cost. Marginal cost pricing is consistent with many optimization concepts. This payment at marginal cost is good for any producer that moves its generator toward the WOLF price. When the movement of the generator toward the WOLF price is an increase in generation, the WOLF price is above the static marginal cost and the generator gets paid for its surplus. When the movement is a decrease in generation, the WOLF price is below the static marginal cost and the generator pays a low price for its shortage.

At the same time that the generator is moving its marginal cost toward the anticipated WOLF price, the WOLF price will be moving toward the generator's marginal cost. The WOLF price is a function of the actual imbalance, the Shortage shown in Figure 3. To the extent that producers increase their generation, the Shortage shown in Figure 3 decreases, which decreases the Price Pressure. Any decrease in the Price Pressure will lower the actual WOLF price for the WOLF pricing interval.

The interaction between the Shortage and the WOLF price has been demonstrated in India, which began using its Availability Based Tariff for pricing Unscheduled Interchange on a dynamic basis in 2002 and 2003. The ABT pricing mechanism for UI uses frequency as the independent variable in a pricing formula for imbalances. The billing interval is 15 minutes. Prior to the implementation of the ABT, system operators spent a substantial amount of their time handling disputes about imbalances and the obligations to pay imbalances back. The ABT pricing mechanism for UI effectively eliminated these disputes. Imbalances are cashed out every 15 minutes.

Figure 4 presents three monthly histograms of system frequency for the Southern Load Dispatch Area of India. During these periods, the SLDA was not electrically integrated with the rest of the Indian grid. As a result, the ACE for the SLDA reduces to system frequency, the horizontal axis in Figure 4, since there was no possibility for interchange with the rest of India.

Figure 4
India Southern Load Dispatch Area, Monthly Distribution of Minute by Minute Frequencies



The left most histogram is for January 2002, a year before the implementation of the ABT pricing of UI. The most common frequency was 48.0 Hertz on a system with a nominal frequency of 50.0 Hertz. The short histogram in the middle of Figure 4 is for January 2003, the first month of UI pricing. The most common frequency is about 49.9 Hertz, a vast improvement over the 48.0 Hertz experienced a year earlier. The tall histogram in the middle of Figure 4 is for July 2004, a year and half after implementation of ABT pricing of UI. I note that subsequent increases in the cost of fuel has resulted in the histograms migrating to the left, to lower frequency ranges, since the pricing curve does not dynamically reflect the current cost of fuel.

In some respects, the left most histogram in Figure 4 can be considered to reflect the shortage absent any response to a WOLF like price. The other histograms in Figure 4 can be considered to reflect the shortage after some response to a WOLF like price. The ABT pricing of UI provides participants a real time marginal cost against which to dispatch their generation. The left histogram was the result of participants having an obscure obligation to return their imbalances in kind.

One problem with marginal cost pricing is the incentive for producers to withhold capacity that would bring the price down even further. One approach to the situation is to offer producers an incremental cost, one based on the WOLF price with and without the generation response to the WOLF price. This provides an incentive for the producers to generate up to a marginal cost equal to the WOLF price. In contrast pure marginal cost pricing provides an incentive for generators to withhold capacity short of the WOLF price. The result of incremental pricing would be slightly different prices for each generator based on their contribution to meeting the projected shortage without the response of the generator.

Shorter pricing intervals for unscheduled flows of electricity will also provide incentives for storage devices, whether conventional storage such as hydro or non-conventional storage such as load management. This is especially true if the prices during periods of shortage are allowed to soar as was illustrated in Table 3.

Conclusion

The presence of wind generators in the ERCOT West market area has greatly depressed the MCPE, not just in the West market area but also occasionally in the rest of ERCOT. The effect on the rest of ERCOT is partially the result of other generators finding it inconvenient or expensive to back down generation when there is sufficient capacity on the transmission lines to allow all of the surpluses in the West market area to reach the rest of ERCOT.

The negative MCPE has likely been insufficient to depress generation in the West market area enough to eliminate the overloads on the transmission system from the West market area to the rest of ERCOT. A dynamic pricing mechanism for very short time intervals may be able to improve the reliability of the network by reducing violations of the n-1 planning and operating criterion. WOLF provides such a mechanism. The Indian ABT pricing of UI has greatly improved the reliability indices on the operation of the grid in India.

Footnotes

[1] Pursuant to a discussion on May 18, 2009 with Ross Baldick, Professor, Department of Electrical and Computer Engineering, The University of Texas at Austin.

[2] The thermal limit of a transmission line generally relates to how lines stretch when they get warm while they carry current. The stretching of the lines allows them to sag, which may lead to contact with underlying vegetation, or may lead to other safety issues. The n-1 criterion refers to preparing for the contingency that one of the lines is knocked out of service and whether the remaining n-1 lines can handle the load without any line reaching its thermal limit.

[3] Pursuant to a discussion on May 18, 2009 with Ross Baldick, Professor, Department of Electrical and Computer Engineering, The University of Texas at Austin.

[4] I do not know the rationale for changing the allocation process. I note that under some legal and economic theories, the allocation of market shares among competing producers is a violation of the US anti-trust statutes, potentially subjecting the participants to treble damages. State actions are often exempt from such anti-trust claims, but participation in an ERCOT market allocation scheme may not have provided such an exemption.

[5] Area Control Error (ACE) is inadvertent interchange biased for frequency error. Inadvertent interchange is unscheduled interchange with neighboring utilities. For an isolated system such as ERCOT, inadvertent interchange is always zero and ACE reduces to frequency error.

Alternative Regulation, Benchmarking, and Efficient Diversification

*By Mark Newton Lowry and Lullit Getachew**

Energy utility companies have for many years had an interest in growth through diversification. The success of such ventures often depends on their ability to integrate the new operations with traditional utility activities. If operations are integrated, substantial production economies are sometimes available. For example, scale economies may be realized from providing traditional utility services in multiple markets. Scope economies may be realized from providing non-traditional services in local markets. Integrated operations can also provide customer convenience benefits.

Diversification initiatives unfortunately raise concerns about cross-subsidization under traditional cost of service regulation (COSR). If new services are provided by the utility, difficult issues of cost allocation arise. To avoid these issues, most utilities have pursued recent diversification chiefly through unregulated affiliates. Under this approach, however, the potential production economies can only be realized if some utility functions are provided by the affiliates. This raises awkward transfer pricing issues. Concerns are sometimes raised, additionally, that utility involvement in non-traditional markets may reduce competition.

Regulators have for these reasons understandably taken measures to avoid having to deal with these issues. For example, utility involvement in non-traditional markets is generally discouraged where it can be avoided.[1] Transfer prices charged by affiliates are carefully scrutinized. Transfer pricing controversies extend in some jurisdictions even to charges by holding companies for overhead services. Codes of competitive conduct have been developed.

The end result of these measures has been to discourage efficient diversification. Utilities generally do not provide non-traditional services. Unregulated affiliates often do not provide services to utilities and those that do not frequently fail. The success of some utilities in spinning off generation to affiliates has worked in part because they have retained the production economies that come from integrated operation of plants serving regulated and competitive markets. The fact that it is relatively easy to identify just and reasonable transfer prices for power has helped policymakers sanction such arrangements.

Diversification ventures that might promote competition are counted amongst the casualties of COSR. For example, many regulators are frustrated by the failure of independent energy marketers to make substantial inroads into retail markets. Natural gas distributors could be major players in retail power markets if they could keep the scope economies achieved from using their customer care units to handle power sales accounts. Electric utilities could play the same role in retail gas markets. However, these players have typically been forced to the sidelines under COSR.

Chastened by failed diversification ventures, many utilities now report intent to refocus on their basic utility businesses. A "return to basics" strategy can be especially attractive for a company with a highly depreciated rate base since, under COSR, replacement investments can in the short run produce a considerable revenue "bump".

Recent developments in regulation can help to finesse the awkward issues that arise from diversification initiatives. These include alternative regulation (Altreg) and statistical benchmarking. This paper considers how Altreg and benchmarking can promote efficient diversification.

Scale and Scope Economies

Economies of scale are most easily understood in the context of firms that make a single product. Scale economies are realized in such a firm when cost grows less rapidly than the amount produced. Average cost then declines with output growth.

Utility companies have attempted to realize scale economies in a number of ways. Many companies provide a similar set of utility services in multiple areas that can span several jurisdictions. Familiar examples include American Electric Power, CenterPoint Energy, Nisource, Pacificorp, and Canada's Fortis.

Another common approach is to provide a certain component of traditional utility service in multiple areas. Services most commonly slated for this treatment have included gas supply and power generation. Some companies have tried to market other utility services in multiple areas. TXU, for example, entered into a $ 3.5 billion 10 year agreement to outsource the company's back office operations - including customer care services, information technology, and supply-chain management – to a new joint venture between TXU and a management consulting firm. The new company, Capgemini Energy, intends to offer its services to other utilities. The ambitious plan involves the transfer of thousands of TXU employees.

Economies of scope exist when multiple products can be supplied by one company more cheaply than if produced by separate, specialized companies. They are so-called because they depend on the scope of a firm's product offerings. Scope economies exist for various reasons. One of the most important is the sharing of inputs. A farmer who grows corn and soybeans, for instance, might find that his land and management services are more fully utilized by raising livestock as well.

---

* Mark Newton Lowry is a Partner and Lullit Getachew (corresponding author), a Senior Economist at Pacific Economics Group, Madison, WI. She may be reached at lgetachew@earthlink.net

See footnotes at end of text.

Two strategies for the realization of scope economies by electric utilities have been widely sanctioned by regulators and pursued by utilities. One is the provision of bundled power service (power supply, transmission, local delivery, and customer care services), an example of vertical integration. The other is the joint provision of gas and electric services.

The Case of BPL

Broadband over power lines (BPL) is an interesting and topical example of a business with potential scope economies for electric utilities. BPL is a technology for providing internet and other broadband communications services to local residential and business customers over distribution lines. Every power outlet in the home can serve as an internet connection. BPL can also serve as the basis for community wireless services. Speeds are in many cases faster than those for the broadband services of phone and cable companies.

The opportunities for scope economies from the joint provision of power distribution and BPL services are palpable. For example, BPL facilitates distribution network automation. BPL obviously needs poles, conduits, and wires but may also make use of distribution personnel who are active in the neighborhood. A billing and collection operation for power services can do the same job for BPL at low incremental cost. There are, additionally, convenience benefits for customers when they can pay one bill for power and broadband services.

BPL is also noteworthy for being a potentially pro-competitive diversification venture. A third player in the local retail broadband market would materially strengthen competitive forces. The pro-competitive value of BPL would be even more marked should telephone and cable service providers consolidate.

Notwithstanding the potential benefits of BPL, the forecast for its success under COSR is cloudy. Many regulators have professed an interest in encouraging BPL. The real question is what they mean by encouragement. In markets that already contain two broadband providers, the success of BPL may hinge on the ability of utilities to capture the production economies and customer convenience advantages that are possible from unified operation. However, the application to BPL of the same diversification policies that have to date been applied to ventures in markets for heating, ventilation, and air conditioning will discourage unified operation.

There is also a question of revenue sharing. An article in *Electric Utility Week* quoted Standard and Poor's as saying that if utilities profit from BPL, "regulators may take notice and require utilities to share at least a portion of that return with the ratepayers. This could potentially dampen the appeal of the investment in BPL".[2] The head of a NARUC task force on BPL is quoted as stating that utility customers "have paid for the poles and infrastructure being used" to provide BPL service and are entitled to a share of the revenue. The article also states that "utilities generally will look to lease their facilities to a BPL provider and share in any revenue from customers buying the service, taking a landlord approach and not getting involved in customer care, billing, and other functions."

Considering the challenges of succeeding at broadband under COSR, it is not surprising that the implementation leaders to date have been distribution co-ops and municipal utilities. Concerns about cross subsidies are less pronounced for utilities with these ownership structures. Some are not even subject to COSR. The best chances for BPL success at investor-owned utilities may be in rural areas where there is less retail broadband competition.

Altreg

The term Altreg describes a general approach to regulation that weakens the link between a utility's rates and its own unit cost. A variety of mechanisms are used for this purpose. One basic approach is to extend the period between rate cases through the use of automatic rate adjustment mechanisms. Another is to base rates only partially on a company's own unit cost when true-ups occur.

Economic science is useful in the design of Altreg plans. For example, economic theory shows that the growth in the cost of a company equals the growth in the input prices that it pays less the growth in the productivity it achieves plus the growth in its output. This result can guide empirical research to develop an index that provides compensatory revenue requirement adjustments. For example, a revenue cap index can be designed for a power distributor that reflects regional input price and productivity trends and the impact on cost of a company's customer growth.

Altreg is the most common form of regulation in utility industries, such as oil pipelines, railroads, and local telecom exchange, where companies serve markets with widely varying competitive pressures. Local telcos, for example, face much greater competition in downtown office districts and in the provision of broadband services than they do in the provision of conventional telephone services to residences. Altreg plans permit companies faced with this kind of challenge to serve varied markets from a common set of assets and thereby to realize the available scale and scope economies. For example, it is easier for regulators to grant local telcos substantial pricing flexibility in the market for large business customers when prices for residential customers are subject to an extended rate freeze. Telcos are not expected to serve competitive markets through affiliates.

Altreg is also the common form of regulation for investor-owned energy utilities overseas. This approach was initially adopted for its convenience in the regulation of privatized companies that were formerly state enterprises. Regulators in most countries where this has occurred have subsequently had the option of adopting

American-style COSR but have generally elected to stay with Altreg.

North American energy utilities as a group have the self-image of operating under COSR. The reality of the industry is, however, somewhat different.

- Many utilities have in recent years operated under extended, formal rate freezes that were components of merger or restructuring agreements.
- Several utilities, aided by slow rate base growth, low energy prices, and falling interest rates, have managed to avoid rate cases for many years at a time. Florida Power and Light, Kentucky Utilities, and Nicor Gas are prominent examples.
- Terms of power purchase agreements with affiliated generators are often deemed just and reasonable if they result from competitive bidding.

The recent resurgence of electric utility interest in rate cases reflects not a return to traditional values so much as a medley of forces that are today placing upward pressure on their unit cost of service. These include rising fuel prices, accelerating rate base growth, and the end of the long secular decline in bond yields.

In addition to informal Altreg, many North American electric utilities have operated under formal Altreg plans. Plans have been approved in such diverse jurisdictions as Alberta, California, Florida, Louisiana, Maine, Missouri, and Ontario. The many North American and overseas Altreg plans encompass a wide variety of mechanisms. These include rate and revenue requirement indexes.

Altreg facilitates efficient diversification by reducing concerns about cross subsidization. Suppose that a utility wishes to diversify into the BPL business. Its success in the business will depend critically on its ability to realize scope economies by sharing inputs that are customarily used to provide local delivery and customer care services. This can raise serious cross-subsidy concerns under COSR.

These concerns can be finessed by a multiyear rate plan. Such plans protect customers from cross-subsidization. They also incent utilities to pursue diversification only if there are real production economies and consumer convenience. An Altreg plan can in principle apply to all distribution revenue or to the cost of those inputs most likely to be shared. For example, a power distributor can in principle maintain COSR for its capital cost but adopt a five to ten year revenue requirement index for its O&M expenses.

To appreciate how this idea would work in practice, consider that Pacific Economics Group recently completed a study on the long term trend in the productivity with which U.S. power distributors use operation and maintenance inputs. The study relied on Federal Energy Regulatory Commission Form 1 data for the 1992-2003 period. It found the productivity trend to be 0.82% growth per annum. Assume, additionally, 2% annual input price inflation and customer growth equal to the 1.72% average annual rate experienced by distributors over the sample period. A revenue requirement index for O&M expenses based on these results could then yield 2.00 – 0.82 + 1.72 = 2.9% annual escalation.

The adaptation of this general idea to other forms of diversification is straight-forward. For example, a utility wishing to outsource its customer care services to an affiliate might adopt a five to ten year revenue requirement index for its customer care expenses. Similarly, a multi-utility company might adopt a five to ten year revenue requirement index for its non-pension A&G expenses. Power purchase contracts with affiliates can also feature Altreg-style indexes.

Statistical Benchmarking

Benchmarking is the appraisal of performance by making comparisons to external performance standards. Statistical benchmarking uses statistical methods to fashion benchmarks and make the comparisons. To draw an example from the world of sports, the eligibility of a slugger for induction into baseball's Hall of Fame can be assessed by comparing his lifetime batting average, RBI, and home run totals to those of players who have already been elected.

Statistical benchmarking of utility cost performance has been underway for more than a decade. A variety of benchmarking methods are available. Many utilities are familiar with simple unit cost measures. These typically lack the sophistication needed for use in the regulatory arena. One obvious deficiency is their inability to control for the many business conditions other than operating scale that affect utility cost. Alternative and more accurate benchmarking methods include productivity indexes and econometric models.

The econometric approach to benchmarking merits discussion as an example of the discipline. Economic theory suggests that the cost of a utility depends on its workload, the prices it pays for inputs, and miscellaneous other business conditions. We might then posit the existence of a function that relates cost to these variables and estimate its parameters statistically using historical data on utility operating costs and business conditions. A cost function fitted with parameter estimates and the local business conditions of a utility can be called an econometric cost benchmarking model. It can predict a utility's cost given various circumstances that are beyond its control. Statistical tests can be used to guide model specification and to consider what conclusions can be drawn about utility operating efficiency.

Statistical benchmarking has growing use in regulation. It is used most commonly to appraise historical or proposed costs during rate cases. Such studies have to date been used most extensively in the regulatory process overseas.

In North America, statistical benchmarking studies have been used more sporadically in regulation. However, the use here of litigation in ratemaking, combined with the abundance of good operating data, has permitted the development of some of the most sophisticated benchmarking studies in the world. The diverse group of utilities that have filed studies in rate cases includes AmerenUE, Atlanta Gas Light, Boston Gas, Kentucky Utilities, Oklahoma Gas & Electric, and Pacific Gas & Electric. Some utilities have filed studies to defend themselves from charges of mismanagement. Others have, like Kentucky Utilities, filed studies to turn a spotlight on exceptionally good management.

Statistical benchmarking can be of considerable use in the regulation of diversified energy utilities. For a utility engaged in BPL, for instance, benchmarking can be used to assess the reasonableness of proposed O&M expenses. For a utility purchasing power from an affiliate in a non-competitive wholesale market, benchmarking can focus on these expenses. A&G expenses can also be benchmarked.

The recent experience of Enbridge Gas Distribution provides an example of the use of benchmarking for such purposes. This Toronto-based company is Canada's largest natural gas distributor. Having entered into a multi-year contract to purchase its customer care services from an affiliate, it recently sold the affiliate. Both actions heightened interest in the reasonableness of its proposed customer care expenses. In this case, statistical benchmarking of the proposed expenses could shed light on their reasonableness.

It is also possible to develop benchmarking models for many electric utility services, including total power distribution cost, A&G expenses, and power generation. To give the reader a flavor of how a quality benchmarking study works, we present here in Table 1 results from a past version of our econometric benchmarking model for power distribution O&M expenses. The results are based on a sample of data from 44 U.S. distributors over the 1991-2003 sample period.

Table 1
Drivers of Power Distribution O&M Cost

Cost Driver	Estimated cost elasticity	t-statistic
Number of Customers	0.41	131.57
Labor Price	0.84	58.40
Average Precipitation	0.10	7.78
Number of Gas Customers	-0.01	-8.91
Distribution Line Length	0.11	7.85
% Dx in Electric Gross Plant	0.17	9.97
% CSI in Dx COM	0.87	11.35
Trend	-0.02	-13.12
Other Statistics		
Adjusted R^2	0.96	
Sample Size	871	
Sample Period	1991-2003	
Number of Companies	67	

We note that all variables included in the model have sensibly-signed and statistically significant parameter estimates. We find, for example, that O&M expenses are higher the greater are the number of customers served and the higher are labor prices. Average precipitation is included in the model as a measure of forestation. The positive parameter estimate suggests that expenses increase with forestation. The number of gas customers is included in the model as a measure of diversification into gas distribution. The negative parameter estimate suggests that such diversification produces scope economies. Distribution line length is included as a measure of system extensiveness. The positive sign suggests that extensive, for example rural, systems involve higher expenses. The share of power distribution plant in the gross value of total electric plant is included as a measure of diversification into generation and/or transmission. The positive estimate suggests that such diversification produces significant scope economies. The share of customer service and information in total O&M expenses also has a positive parameter estimate. This is the expense category in which demand-side management costs are typically recorded. The positive parameter estimate suggests that DSM programs raise total distribution O&M expenses. Note, finally, that the trend variable has a negative parameter estimate. This suggests that O&M expenses shift downward over time for many reasons including technological change.

We present in Table 2 some benchmarking results generated by the model for the sampled companies. We report the percentage difference between the costs incurred by the utilities over the three-year 2001-2003 period and the corresponding cost predictions of the model. A negative number indicates that actual cost was below the model's prediction. Given the experimental nature of the model, we report results only for the companies with expenses that are lower than the model's prediction.

In assessing the results, it is important to consider that the model may not account for all potentially important sources of variation in O&M expenses. The results are also sensitive to our method of allocating a portion of A&G expenses to distribution.

Hybrid Approaches

Altreg and statistical benchmarking can be used together to promote efficient utility diversification. Suppose, for example, that a utility engaged in BPL is coming to the end of a ten year indexation of its distribution O&M expenses. Difficult issues of cost allocation and/or transfer pricing may then arise. Statistical benchmarking can play a useful role in the appraisal of the company's proposed O&M expenses going forward.

Conclusions

This article has addressed a central problem with the cost of service approach to regulation: its awkwardness in handling utility diversification. The result has been to discourage efficient diversification and to limit the posi-

Table 2
Top Power Distribution O&M Cost Performers, 2001-2003

Utility	% Difference Actual and Predicted O&M Cost	Utility	% Difference between Actual and Predicted O&M Cost
Tucson Electric Power	-0.48	Green Mountain Power	-0.16
Texas-new Mexico Power	-0.45	Edison Sault Electric	-0.14
Potomac Edison	-0.40	Columbus Southern Power	-0.14
Union Light Heat & Power	-0.32	Toledo Edison	-0.13
Wisconsin Electric Power	-0.32	Florida Power	-0.12
Virginia Electric & Power	-0.31	Public Service Electric & Gas	-0.10
Wisconsin Power and Light	-0.26	Bangor Hydro Electric	-0.10
Florida Power & Light	-0.25	Kingsport Power	-0.10
Kentucky Utilities	-0.25	Tampa Electric	-0.10
Public Service of New Hampshire	-0.23	Northern States Power	-0.06
Public Service of Colorado	-0.22	Wisconsin Public Service	-0.06
Oklahoma Gas and Electric	-0.21	El Paso Electric	-0.05
Empire District Electric	-0.20	Northern Indiana Public Service	-0.05
Carolina Power & Light	-0.20	Louisville Gas and Electric	-0.04
Southern Indiana Gas & Electric	-0.19	Connecticut Light & Power	-0.02
Public Service of Oklahoma	-0.18	Cincinnati Gas & Electric	-0.01
West Penn Power	-0.16		

tive role that utility companies can play in our economy. Alternative regulation and benchmarking can reduce cross-subsidy concerns and help utilities to capture more of the production economies and customer convenience benefits that diversification can afford. There are numerous ways to implement Altreg and no one way is best for all utilities. Regulators should carefully consider the Altreg option and, more generally, reconsider policies that discourage diversification, especially where it can help to promote competitive markets.

Despite the appeal of Altreg and benchmarking, it is certainly possible for BPL to succeed under COSR if there are changes in the way that it is conducted. BPL affiliates would naturally be expected to pay their share of the incremental costs resulting from BPL deployment. However, regulators should be very careful about asking these affiliates to bear sunk costs of the distribution network.

Footnotes

[1] Some involvement by utilities in non-traditional markets is unavoidable. An example is the disposition of land beneath transmission lines.

[2] "Study Says Utilities Face Challenges on BPL as State Regulators Mull Policy Suggestions." *Electric Utility Week*, 18 November 2004, pp. 1 and 6-7.

Webcasting a USAEE Chapter Meeting

To expand upon the USAEE's mission to "provide a forum…for the exchange of ideas, advances and professional experiences," (www.usaee.org) the Houston chapter, in cooperation with Rice University's Baker Institute, broadcast its April 2009 meeting as a webcast. The Houston meeting was open to local USAEE members and non-members, Rice university students and the webcast participants. The meeting served as a trial of how USAEE chapters can work to promote the development and education of energy professionals and students both locally and nationally. Webcasting chapter meetings can extend member benefits beyond those currently available via local chapter meetings and USAEE publications and conferences.

Developing a Webcast

The Houston chapter officers coordinated with the appropriate parties at Rice's Baker Institute to secure the facilities, A/V equipment and catering for the April meeting. As this was a joint event, the Baker Institute kindly waived the facility fee, leaving only the A/V staffing and editing/post-production fees in addition to the catering bill. Boxed lunches were served prior to the meeting presentation giving attendees the opportunity to network. Serving lunch first limited the potential for any late-arriving attendees to disrupt the presentation once it was in progress, as any commotion in the amphitheater would be picked up by the webcast recording equipment.

Energy Cost Trends

For this webcast, Candida Scott, CERA Senior Director for Cost and Technology, presented on "Energy Industry Cost Trends". With more than twenty-five years of industry experience, Ms. Scott currently oversees IHS/CERA's Upstream Capital Cost Index. For the webcast meeting, Ms. Scott specifically focused her presentation on upstream construction trends.

Her presentation began with an overview of capital cost indexes for upstream, downstream and North American power, showing costs beginning to rise significantly around 2004. From that point, Ms. Scott progressed to a discussion of the current recession and lessons the energy industry learned from its experience in the 1980s. She quickly touched on the 2009 world GDP decline and recent rise in oil spare capacity before delving into further discussion of rig utilization rates, which serve as a performance "barometer" for the upstream sector. Ms. Scott pointed out that even though the 2008 oil price decline was much more severe than the one seen in the early 1980s, this time the industry has experienced greater rig utilization stability. She attributed this increased stability partially to high cancellation cost clauses included in deepwater rig contracts and to the significant increase in national oil company (NOC) activity over the past thirteen years. Even so, Ms. Scott warned that nearly 7.6 mb/d of capacity growth is at risk of deferral if the industry continues to see declines in commodities prices, industrial activity, rig utilization and other areas. To wrap up her presentation, Ms. Scott returned to her initial slide on cost indexes, questioning the shape of future cost models.

A Great Turnout

By webcasting Candida Scott's presentation, the Houston chapter connected with a larger audience than it can typically reach through its monthly meetings. The April meeting drew an audience of approximately seventy-five in-person attendees plus more online viewers. On behalf of the chapter, Michael Canes, Vice President - Chapter Liaison for the USAEE, had sent out an announcement to all USAEE chapters publicizing the upcoming webcast event. Of those attending in-person, almost half were students. Partnering with the Baker Institute provided an excellent opportunity for Rice students to hear from an industry speaker. Ms. Scott's presentation on upstream costs related well to fundamental issues currently facing the energy industry and of which the Rice students have been studying. The students also had the opportunity to network with USAEE members during the luncheon part of the meeting. According to Ken Medlock, adjunct professor and the James A Baker, III and Susan G Baker Fellow in Energy at Rice, "there was a visible interaction between the students and the general membership in attendance. This, in fact, was expressed by several of the students to be one of the most beneficial aspects of the luncheon meeting."

Keys for Hosting a Successful Future Webcast

As there was no online registration for the webcast, the actual number of online viewers is unknown. Ben Schlesinger, president of the National Capital Area Chapter, said he heard that "some of our members tuned in" but that his chapter did not participate in any preannounced way. For record-keeping purposes, online registration will help the broadcasting chapter know exactly who participated in the event. Knowledge of this participation will be beneficial in targeting and promoting future USAEE chapter webcasts as well as surveying participants.

Of those who did participate online, some suggestions were made for future webcasts to create an enhanced viewing experience. USAEE chapters looking to emulate Houston's webcast experiment should begin by considering whether or not their current meeting venues are conducive to webcasting speaker presentations. Due to security restrictions, the Houston chapter's customary meeting venue is unable to accommodate webcasts. As such, the chapter must seek out other venues and partnerships, such as the one established with Rice's Baker Institute, in order to webcast its presentations.

Once the broadcasting chapter has selected an appropriate meeting location, it must focus on constructing a user-friendly webcast platform. The Houston chapter relinquished all webcasting responsibility for its April presentation to the Baker Institute. While this made the webcast's implementation much easier from the chapter's perspective, it also subjected the presentation to the Institute's webcasting platform. Some web viewers had difficulty accessing the presentation via the Baker Institute's website as the event program time was not clearly stated. Viewers who logged on at the event's advertised start time of 11:30 a.m. (CDT) were unable to find the webcast since the presentation began almost an hour later, following the boxed luncheon for the in-person attendees. Online attendance may have been higher had there been a screen message notifying web viewers that the webcast would begin shortly. Alternatively, the speaker presentation could have preceded the catered lunch. Having the presentation first would have prevented the confusion surrounding the event start time and eliminated any need for a screen message, though doing so would have meant late-arriving attendees could have potentially interfered with the webcast recording quality.

In addition to a better event time schedule, online viewers expressed a desire to have increased participation abilities. Some viewers were frustrated that the webcast platform used for the April meeting did not allow them to submit questions for the Q&A session. Other chapters can avert this frustration by using a webcast program that allows question submission, opening up an instant messenger program to receive questions or having viewers submit questions to the chapter's email address.

A Great Opportunity

Initially, small hiccups are to be expected as chapters begin to experiment with webcasting their meeting presentations. With practice and increased communication between chapters, initial stumbling blocks will dissipate. Existing USAEE chapter members can benefit greatly from this technological aid, strengthening the relationships between chapters while also increasing student involvement.

Ariana Landry
Financial Analyst
Williams Gas Pipeline
Secretary
USAEE Houston Chapter
Ariana.Landry@williams.com

Announcement

12th Annual IAEE/USAEE Session at ASSA Meeting

Atlanta, Georgia – January 3, 2010

Meeting Room and Time TBA

"Energy Security for Renewables and Non-renewables"

Presiding: Mine Yucel, Federal Reserve Bank of Dallas

Gail Cohen, US Congress Joint Economic Committee, Frederick Joutz, George Washington University, and Prakash Loungani, International Monetary Fund – *The Determinants of Energy Vulnerability and Security: An Empirical Analysis*

Stephen P.A. Brown, Resources for the Future and Hillard G. Huntington, Energy Modeling Forum, Stanford University – *Reassessing the Oil Security Premium*

Christian Winzer, Karsten Neuhoff, and Daniel Ralph, University of Cambridge – *Measuring Security of Supply*

Kevin F. Forbes, Catholic University of American, Marco Stampini, African Development Bank, and Ernest M. Zampelli, Catholic University of America – *Do Higher Wind Power Penetration Levels Pose a Challenge to Electric Power Security?: Evidence from the ERCOT Power Grid in Texas*

Discussants:
Andre Plourde, University of Alberta
Ken Medlock, Rice University
Xiaoyi Mu, University of Dundee
Wumi Iledare, Louisiana State University

Abstracts are posted at http://www.iaee.org/documents/2010/assa_cfp.pdf

The meeting is part of the Allied Social Science Association meetings (ASSA).

For complete program information please visit http://www.vanderbilt.edu/AEA/Annual_Meeting/index.htm

Also, please watch for the IAEE/USAEE Cocktail Party.

Working Paper Series

— CALL FOR ENERGY RESEARCH PAPERS —

The USAEE has created a working paper series that gives you (and all USAEE members) a chance to increase the circulation, visibility, and impact of your research. If you have an unpublished research paper that addresses any aspect of energy economics or energy policy, we would like to feature your paper in this new series. There is no cost to you, only benefits:

- Place your work where it can be seen and used on a daily basis.
- Gain timely feedback from other researchers working on related topics.
- Create a permanent and searchable archive of your research output within the largest available Electronic Paper Collection serving the social sciences.
- Provide unlimited, hassle-free, public downloads of your work on demand.
- Raise your research profile, and that of the USAEE, by joining with fellow USAEE members to establish a new energy research *trademark* that is unparalleled in terms of its breadth and depth of focus.

The *USAEE Working Paper Series* is a new component of the Social Science Research Network (SSRN) *Research Paper Series*. SSRN is the leading online source of full-text research papers in the social sciences, and is accessible at the following link: http://www.ssrn.com/. SSRN is indexed by Google and all other major online search engines, ensuring that anyone who does a keyword search in your area of research will be directed to your paper, including free downloads, and provided with your contact information. SSRN tabulates the number of abstract and full-text downloads of each paper in the series and publishes various "top-ten" lists to indicate which papers are most highly demanded within individual subject areas.

To view current working papers in our series please click here

Contributor Guidelines

The *USAEE Working Paper Series* includes only papers that present original, scholarly research related to energy economics and policy. Editorials, marketing tracts, and promotional material will not be accepted. Other than this initial screening, the working papers will be unrefereed and authors are solely responsible for their content. Authors will retain all rights to their work, including the right to submit their working papers (or subsequent versions thereof) for publication elsewhere. Neither USAEE nor SSRN will assume or usurp any copyright privileges with respect to papers included in the series.

Each working paper included in the *USAEE Working Paper Series* must be authored or co-authored by a member in good standing of the USAEE, and be submitted by that member. All papers will be assigned a USAEE Working Paper number and fitted with a distinctive cover page that identifies it as part of the USAEE series.

To include your research paper (or papers) in the *USAEE Working Paper Series*, please email a copy of the work (in MS Word format), including a brief abstract, to the addresses given below.

Kevin Forbes
USAEE Working Paper Series Coordinator
Catholic University
kevin.f.forbes@gmail.com

David Williams
USAEE Executive Director
usaee@usaee.org

Scenes from the 32nd IAEE International Conference

June 21–24, 2009 — San Francisco, California, US













Highlights from the 32nd IAEE International Conference

This year's conference was held in San Francisco, California. The three-day conference attracted more than 350 attendees and highlighted renewable energy as one of the most popular topics of the conference. But oil & gas industry issues such as oil price, LNG trade and unconventional resources, prospects of the nuclear industry and environmental challenges were not ignored. Following are observations from some of the plenary sessions.

The conference started with a welcome and opening talk of **Joseph Dukert**, General Conference Chair and President of the United States Association for Energy Economics. He gave a brief thanks to conference committee members and conference sponsors. **Georg Erdmann**, President of the International Association for Energy Economics (IAEE), outlined main conference topics, setting the context by referring to the effects of financial and economic crisis on energy sectors, primarily on the oil and gas industry, and the effects of economic recession on GHG emissions and upcoming climate talks on following the Kyoto treaty.

During the keynote speech, **Gary G. Mar, Q.C**., representative of the Government of Alberta discussed the state Alberta's economy, its place in energy field, and its actions on climate change. Mr. Mar referred to climate change as a global problem that needed a global solution. He said "Looking at the national and international level, both Canada and the United States are moving forward with new climate change legislation and the world will be gathering in December to replace the Kyoto Protocol." With respect to GHG regulatory framework, Mr. Mar mentioned the importance of finding balance and harmony among energy production, environmental responsibility and economic growth. Alberta has the world's second largest proven oil reserves and produces around 1.7 million barrels of oil per day with three-quarters of that production coming from the oil sands. It is the largest exporter of oil to the U.S. and also provides almost 50% of U.S natural gas imports, which is equal to 8% of total U.S. consumption.

The plenary session on climate change policies was chaired by **James Sweeney**, Director of the Precourt Institution for Energy Efficiency, Stanford University. **John Weyant** from Stanford University talked about their latest research on domestic and international climate change policy scenarios. For international study they mainly run 10 different models with 10 different scenarios and for domestic study there were 6 different models with 3 different scenarios. International scenarios are combinations of three concentration goals based on Kyoto gases, two means of achieving concentration goals, and two international policy regimes. The ten models, Mr. Weyant listed, are ETSAP-TIAM (Canada), FUND (E.U.), GTEM (Australia), IMAGE (E.U.), MERGE (U.S.), MESSAGE (E.U.), MiniCAM (U.S.), POLES (E.U.), SGM (U.S.), and WITCH (E.U.). Emission reductions and economic cost of scenarios varied from model to model. For domestic study 3 different Cap & Trade scenarios were applied by using 6 different models. All models showed reductions in emission through 2050. MiniCam model was the one which led to highest reduction. When the carbon prices were compared MiniCam gave the lowest price. When it comes to sectoral comparison, electricity generation and transportation sector had the greatest reduction with each model type. Moreover, each scenario and each model reflected energy consumption loss through 2050.

Mr. Kennedy from California Air Resources Board gave a presentation titled "Climate Change in California". His presentation mainly focused on energy efficiency as a great tool for emission reduction. He looked for answers of the questions; "What would be achieved by consuming energy more efficiently? How to make California's economy much more energy efficient?" Transportation sector was responsible for 40% of emissions in California mainly due to improvements in gasoline quality, supplying low carbon fuels, supporting alternative fuel vehicles such as biofuels, electric, and hydrogen. His main focus was keeping the pressure on the efficiency topic and making it publicly known as well as emphasizing its impact on energy prices.

Brian P. Flannery, manager of Science Strategy and Programs, Exxon Mobil Corporation, gave an interesting talk on Climate Change Policy by comparing Cap & Trade with Carbon Tax. He started his talk with the phrase of "Climate policy requires a risk management framework and brings uncertainty. Stabilization requires global participation including both developed and developing countries." He listed

- Agreeing on "fair" national caps through international negotiation
- National capacity to implement and enforce economy-wide caps
- Wealth transfers
- Assuring international compliance
- Linking national and regional trading schemes
- Credibility and integrity of a common carbon/GHG currency
- Transitions as system evolves

as the challenges on initiating a global GHG-Carbon Market. The primary challenge is to set a uniform and predictable cost of GHG emission reduction. Those kinds of market prices drive the solutions by promoting global participation. However, the price volatility

- Undermines long-term planning and investment
- Creates economic inefficiency
- Enhances wealth transfer to trading from actions to reduce emissions

He said that there was a need for a common CO_2 price for a long term mitigation objectives.

In the special session, **Mark Finley**, General Manager, Global Energy Markets of BP, talked about "Volatility and Structural Change", starting with a general discussion of the world economy; the decline trends in both GDP and world trade growth. Then, he analyzed the energy prices; recession in oil, coal, and gas prices from the beginning of 2008. At the beginning of 2008, the oil production growth decreased by almost -1,5 million barrel/d. However, there was a significant growth of gas production in Gulf of Mexico between 1999 and 2008. Coal consumption also showed dramatic decrease all over the world, except India and China. Wind and solar energy capacities were increased; 30% growth in worldwide wind capacity and 70% growth in worldwide solar capacity.

The plenary on "The future of renewable" was governed by **Gary Stern**, Southern California Edison. **Robert M. Margolis**, National Renewable Energy Laboratory, mainly covered three issues: implementing renewable electricity, using energy efficiently in various sectors, and finding substitutes for fossil fuels. He also discussed technological challenges to renewable energies such as their integration into the existing grid. **Todd P. Strauss**, Pacific Gas & Electric Company, pointed out the importance of implementing long-standing state policies to encourage the use of energy efficient technologies and renewable resources. A discussion of various legislations and deadlines imposed by the government of California underlined the challenge to companies such as PG&E. Finally, **Ryan Pletka**, Black & Veatch Corporation, summarized his observations on U.S. renewable energy trends. About 3% of 2008 electricity generation came from renewable sources, 1.3% of which was from wind and 1.4% of which was from biomass. A comparison of costs of renewable energies with those of conventional resources, and tax and subsidy policies was very informative.

The plenary on "Drivers of oil price and the outlook for the future" was chaired by **Samuel A. Van Vactor**. **Robert McCullough's**, in his talk titled "Pickens' Peak Redux: Fundamentals, Speculation or Market structure", focused on the relationship between the price of oil and few critical variables. Comparing the OECD inventory data with the price movements (an increase of 45% in 2008 and a drop of 80% in 2009); he concluded that there was a disconnect between market fundamentals (demand & supply) and the price. In a linear regression analysis, he also investigated the role Dow Jones, Euro, and non-commercial acquisitions among others. Some of the results were interesting; for example, there was no clear relationship between Euro and European oil demand as some might have claimed. Picking up on the same theme, **Jeffrey H. Harris**, Chief Economist at the Commodity Futures Trading Commission, focused on crude oil, pointing out the price changes of recent times: +66.8% between January '07 and February '08 versus -62.8% between February '08 and February '09. He briefly talked about trading behavior and hedge funds stabilizing before going into the use of econometric techniques such as ARCH, GARCH and Granger causality test in analyzing the price movements and their reasons. He voiced a question that is in everyone's mind: do commodity index traders' investments increase prices? CFTC's recent interest in establishing federal limits on speculative positions for finite commodities like oil probably answers that question.

The second day of the conference started with the dual plenary sessions. The first plenary, "Energy Market Developments in the Pacific Basin," was directed by Mr. **Kenichi Matsui**, Institute of Energy Economics. **Micheal Lynch**, Strategic Energy & Economic Research, started his talk by pointing out energy security problem and difficulty of accessing the resources. Japan, Korea, and China have the most significant strategic reserves. All of these countries need large imports of oil and natural gas. The global natural gas market continues to evolve and present various risks in supply but probably more so in demand, partly because of lacking market price signals. As such, pricing of long-term contracts indexed to oil or products, be it pipeline or LNG, becomes risky with long-term impact. **David Fridley** from Lawrence Berkeley National Laboratory focused on the role of coal in China, which is the largest coal based economy in the world. Local coal consumption in the country showed a drastic growth from 1980 to 2005. The industrial sector accounts for 75% of total consumption. Moreover, 80% of China's electricity generation is coal based and it is expected that coal based CO_2 emission of China will exceed the total emission of the U.S. in 2010. **Makoto Takada**, Institute of Energy Economics, talked about nuclear applications in Asia. There is a long history of nuclear power in several countries. The lack of emissions also renders nuclear a good option under a scenario of increased GHG regulation. But there are problems facing the expansion of nuclear capacity in Asia, including grid integration, training of staff (especially for safety) and proliferation risks. Working with small and medium sized reactors could overcome some of these concerns.

The dual plenary session "Unconventional Resources: Impacts and Issues" was chaired by **Andre Plourde**, University of Alberta. **John Wimer**, U.S. DOE, National Energy Technology Laboratory, focused on affordable, low-carbon diesel fuel from domestic coal and biomass. In a world of increasing demand for energy, especially from the emerging economies, the role of oil will remain essential as more people become mobile. Looking for alternative fuels for the transportation sector that is also cleaner burning is a main challenge for NETL. Coal resources, as in many countries, are large in the U.S.; the ability to derive low-carbon diesel fuels from coal as well as biomass via gasification and liquefaction could go a long way towards increasing energy security and reducing emissions, assuming carbon capture and sequestration. **Frits Euderink** from Shell E&P Company discussed unconventional resources such as heavy oil/ oil sands, oil shale, and gas-to-liquids, and biofuels that have been recognized as important ways of meeting growing global energy demand of the world. In the U.S. resource base can be as large as 1.5 trillion barrels. But recovery of such resources faces many challenges: high costs, land reclamation, water management, emissions and regulatory and permitting processes. Carbon capture and sequestration again becomes a necessary but not sufficient condition for garnering support around the development of these resources. **Gordon Pickering**, Navigant Consulting talked about "The Dynamics of Abundance of North American Domestic Natural Gas Supply." U.S. gas production increased due to a decade of increased unconventional production. Production in gas shale had the most dramatic increase. Major Shale Basins in North America showed a remarkable growth. Mr. Pickering believes that EIA continues to underestimate potential growth in gas supply: there is 15 bcfd difference between EIA and NCI forecasts for 2020. One way to use this difference is GTL, which could meet 75% of diesel needs in 2020.

Before a remarkable reception in Exploratorium, the afternoon dual plenary sessions were held. "Energy Market Integration - Developments in LNG" session was chaired by **Glen E. Sweetnam** from the DOE/EIA. **Fisoye Delano** from Poten & Partners discussed recent LNG market trends. For years, LNG meat Japan but new major markets have been growing 17% per year versus 3% per year growth in traditional major markets. The LNG market is also much more diverisiefed and flexible with seasonal contracts and destination clauses. Power generation will drive the need for LNG. The current overhang over LNG supply will dissipate after 2013, pending clarity on LNG project costs and timely FIDs to bring on new supplies when they will be needed. **Christian von Hirschhausen**, Technische Universitat Dresden, talked about competition, contracts and cartel in the world natural gas industry. Europe, Japan, China, India, Indonesia and South Korea are the major LNG importing countries and their import capacities are growing year by year. Contract duration is positively correlated with project specific investment. Mr. Hirschhausen, then, introduced WGM, World Gas Model, as a simulation model of the global natural gas market. WGM is a partial market equilibrium model with optimization problems for individual players. Model results indicate that the risk of a gas cartel or Russian dominance is manageable and that the increased shale gas production in the U.S. may impact LNG trade expectations.

William J. Pepper from ICF International introduced International Natural Gas Model. This model

- Simulates production, processing, transport, transformation, and demand for natural gas globally
- Models activities for 60 nodes with 16 regions
- Demand information comes from EIA WEPS+ and NGTDM model
- But modified for higher electricity demand in the U.S.
- Used to develop reference scenario through 2030 and sensitivities looking at oil prices and shale oil resources

Base case scenario results of the model showed that

- Global demand for natural gas is growing by sector and by region: As a region Middle East share and as a sector power generation share are the largest in 2030.
- Global production by type: conventional onshore stays almost same until 2030 while tight/shale grows.
- Global production by region: Russia and Middle East shares grow.
- Tight/shale production by region: China has the highest volume.

Kenneth B. Medlock, Rice University, chaired the dual plenary session "Energy Market Integration - Developments around the Globe." **Mark K. Jaccard**, Simon Fraser University focused on climate policy in Canada and what we learned from past policy failures. Differences between resource rich provinces such as Alberta and Saskatchewan, fear of losing export competitiveness due to higher cost of production and inability and/ or unwillingness of politicians and major interest groups to recognize that "non-compulsory policies" have negligible effects. Mark also demonstrated that international offsets, especially if they are cheap and can be used to meet large chunks of emission reduction obligations undermine local emission reductions. **Carlo Andrea Bollino**, GSE talked about road to Copenhagen in Europe. EU climate action and renewable energy package has a goal of limiting global average temperature to an increase no more than 2ºC above preindustrial levels. EU wants to achieve this goal by leading the clean technology development sphere as it tries to balance energy security, economic competitiveness and environmental sustainability.

Conference Chair, **Fereidoon P. Sioshansi** directed the plenary session on "International Trends in Nuclear Power." Perhaps not surprisingly, there was strong French presence. **Ana Palacio** of Areva presented nuclear energy as one of the solutions to climate change problem. There is increasing demand for nuclear technology around the world with many countries wanting to build their first plants. Technology is advancing to increase safety. High capital costs remain a challenge. A list of other issues also impact nuclear decisions: regulated v deregulated markets, existence and severity of carbon regulation, size and financial capability of utilities, electricity demand growth rate and availability of alternative fuels such as coal and natural gas. **Jean-**

Pierre Benque from EDF Development presented along the same lines as Ms. Palacio, emphasizing low-carbon benefits of nuclear energy. An important point is that standardization of fleet as is the case for EDF in France. **Chris Larsen**: Mr. Larsen who is a Nuclear Power and Chief Nuclear Officer from Electric Power Research Institute, EPRI, talked about today's nuclear power options and mentioned mission of EPRI: to perform research to sector and society.

The concurrent sessions of this year's conference covered, as usual, a wide range of topics with many good papers, salient presentations, high attendance and lively Q&A sessions. Conference participants also enjoyed the social program of the conference. Overall, it was an enjoyable, informative and productive conference.

Nihan Karali
Center for Energy Economics
Bureau of Economic Geology
University of Texas at Austin and
Industrial Engineering Department
Bogazici University

Congratulations 2009 USAEE Award Winners

Awards committee chair Peter Nance and his committee members Fred Joutz, Jim Smith, Mine Yucel and Jay Zarnikau are pleased to announce the following 2009 USAEE Award winners:

USAEE Adelman-Frankel Award

Awarded to an organization or individual for unique and innovative contributions to the field of energy economics.

Paul Joskow
Alfred P Sloan Foundation

USAEE Senior Fellow Award

Awarded to individuals who have exemplified distinguished service in the field of energy economics and/or the USAEE.

Maureen S. Crandall
National Defense University

Frederick L. Joutz
George Washington University

The above award recipients received their awards and recognition at the 32nd IAEE International Conference, June 21-24, in San Francisco, CA.

Welcome !! The following individuals joined USAEE from 3/1/09 - 6/30/09

Anna Aeloiza

Mi Swaco

Vineet Aggarwal
Chevron

Gregory Anderson
Southern California Gas Company

Manel Avella Fluvia
Columbia University

Edward Balistreri
Colorado School of Mines

Kristin Barbato

Galen Barbose
Lawrence Berkeley National Lab

Justine Barden

Dieter Beike
Independent Consultant

Robert Bessette
Council of Industrial boiler Owners

Charles Breeden
PA Consulting Group

Rafael Campo
Consultant

Michael Castillo
BP

Navin Chaddha
Mayfield Fund

Qimin Chai
Tsinghua University

Jonathan Chanis
New Tide Asset Mgt LLC

Burcu Cigerli
Rice University

Whitney Colella
Sandia National Laboratories

Joel Crane
Deutsche Bank

Eric Cutter
Energy & Envir Economics Inc

Benjamin Davis

J R DeShazo
UCLA

Delavane Diaz
Electric Power Research Institute

Joel Dogue
EDF Development Inc

David Ehrhardt
Castalia LLC

Federico Fische

Nicole Forbes
Texas State University

RoseAnne Franco
PFC Energy

Julia Frayer
London Economics International LLC

David Gaskin

Abbas Ghandi
University of California Davis

Jordon Grimm
US Department of Energy

Reza Haidari
Point Carbon

Gregory Hamm
NERA

Don Irby
Irby Strategic Services

Gwendolyn Jacobs

Nils Janson
Castalia LLC

Fredrich Kahrl
University of California Berkeley

Wincenty Kaminski
Rice University

Mustafa Khan

Manoah Kiletty
Castalia LLC

Andrew Knox
Booz Allen Hamilton

Barnett Koven
World Information Transfer UN

Vanessa Kritlow

Praveen Kumar
University of Houston

Richard Lattanzio

Marc Le Page
Consulate General of Canada

Ja Chin Audrey Lee
US Department of Energy

Billy Leung
Regional Economic Models Inc

Carl Liggio
Pharos Enterprise Intelligence LLC

Carleton Lindgren
PA Consulting

Chiara Lo Prete
Johns Hopkins University

Amber Mahone
Energy & Envir Economics Inc

David Manowitz
University of Maryland

Hari Mantripragada
Carnegie Mellon University

Rafael Martinez
Commodity Futures Trading Comm

Erik Mielke

Merrill Miller

Wolfgang Moehler

Boris Monov
GDF Suez NA Gas and LNG

Mathey Morey
Christensen Assoc Energy Cons LLC

Roxana Muzzammel

Yuichi Nagano
Tokyo Electric Power Company

Iman Nasseri
Univ of Hawaii Econ Res Org

Sebastian Nilsson
Shattuck St Marys School

Jose Ordonez
LCG Consulting

Anthony Papavasilliou
UC Berkeley

Samuel Papendick
Colorado State University

Chul Park
Commodity Futures Trading Comm

William Pepper
ICF International

Deborah Peppers
NRGx2

Carla Peterman
Lawrence Berkeley National Lab

Gordon Pickering
Navigant Consulting Inc

Debra Pyle
James A Baker Inst for Public Pol

Kevin Richards
Castalia LLC

Manuel Rincon

Sean Robinett
San Jose State University

Robert Ryan
US Dept of Energy EIA

Susan Sakmar
Univ of San Francisco Law School

David Sam

Urmi Sen

Gary Serio
Entergy Corporation

Steve Shankle

Stephanie Shipp
Science and Tech Policy Institute

Jaswant Sihra
BP plc

Ashutosh Singh

Colin Smart
Consolidated Edison Co of NY

Michael Stadler
Lawrence Berkeley National Lab

Jeb Stenhouse
Environmental Protection Agency

Lauran Sturm
The Stites & Harbison

Samir Succar
NRDC

Ted Temzelides
Rice University

Brinda Thomas
Carnegie Mellon University

Bob Tippee
Oil & Gas Journal

Mark Tremblay
HQ Energy Services US

Chi Chung Tsao
University of California

Corey Walrod
Conoco Phillips

James Watson
Pearson Watson Millican and Company

John Wimer
Nat'l Energy Technology Laboratory

Matt Wittenstein
London Economics International

Lawrence Wolf

Rose Zdybel

Xinya Zhang

Xiaoli Zhao
Student

Byron Zimmermann
BP

USAEE Student Scholarship Fund: A Call for Support

USAEE is proud to continue its student scholarship fund. Funds are used to help support the Associations best paper award event and other scholarly programs.

2009's student scholarship fund has been generously provided by the support of the following organizations/individuals:

IAEE
Southern Company

Robert Borgstrom
Carol Dahl
Joseph & Betty Dukert
Fred Joutz
Andre Plourde
Jurgis Vilemas
Namejs Zeltins

Recognizing the need for interested and qualified graduates, many funding organizations view the program as supporting education as well as recruitment. The USAEE has started its campaign for scholarship funds for the 2010 USAEE/IAEE North American Conference in Calgary, Alberta, Canada, October 14-16, 2010 and other scholarly projects. Contributions have ranged from $100 to $5000. If you would like to receive information on how your or your company can become a supporter of this program, please contact USAEE Headquarters at (p) 216-464-2785 or usaee@usaee.org

Calendar

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

8-10 September 2009, Cleantech Forum XXIII, Boston at Boston Convention & Exhibition Center, Westin Boston Waterfront Hotel, Boston, Massachusetts. Contact: Cleantech Group, USA. Phone: +1 (810) 224-4310 Email: info@cleantech.com URL: http://cleantech.com/bostonforum

8-9 October 2009, 29th Annual Bonbright Center Electric & Natural Gas Conference at Buckhead, Georgia. Contact: Wendy Richardson, Marketing Manager, Terry College of Business, 110 E Clayton St Ste 602, Athens, GA, 30602, USA. Phone: 706-425-3058. Fax: 706-369-6078 Email: wendyr@terry.uga.edu URL: http://www.terry.uga.edu/exec_ed/bonbright/

November 30, 2009 - December 2, 2009, Canadian Renewable Fuels Summit at Vancouver, British Columbia, CANADA. Contact: Deborah Elson, Director Member Relations and Industry Promotions, Canadian Renewable Fuels Association, Suite 1005, 350 Sparks Street, Ottawa, ON, K1R 7S8. Phone: 613-594-5528. Fax: 613-594-3076 Email: d.elson@greenfuels.org URL: www.greenfuels.org

6-9 June 2010, 33rd IAEE International Conference: The Future of Energy: Global Challenges, Diverse Solutions at Rio de Janeiro, Brazil. Contact: IAEE Conference Secretariat, IAEE, 28790 Chagrin Blvd Ste 350, Cleveland, OH, 44122, USA. Phone: 216-464-5365. Fax: 216-464-2737 Email: iaee@iaee.org URL: www.iaee.org

26-27 August 2010, 11th IAEE European Conference: Energy Economy, Policies and Supply Security: Surviving the Global Economic Crisis at Vilnius, Lithuania. Contact: David Williams, Executive Director, IAEE, 28790 Chagrin Blvd., Ste. 350, Cleveland, OH, 44122, USA. Phone: 216-464-5365. Fax: 216-464-2737 Email: iaee@iaee.org URL: www.iaee.org

14-16 October 2010, 29th USAEE/IAEE North American Conference: Energy and the Environment: Conventional and Unconventional Solutions at Calgary, AB, Canada. Contact: USAEE, 28790 Chagrin Blvd Ste 350, Cleveland, OH, 44122, USA. Phone: 216-464-2785. Fax: 216-464-2768 Email: usaee@usaee.org URL: www.usaee.org

Dialogue Disclaimer

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

Dialogue Article Submission Guidelines

The United States Association for Energy Economics publishes **"*Dialogue*"**, the official Newsletter of USAEE, three times a year. The *Dialogue* is included with your membership dues to USAEE and is available for download at http://www.usaee.org/newsletter.html.

Each issue features a Message from the President, articles written energy professionals, listings for upcoming conferences, a calendar of events, and other news relating to USAEE and the energy field. The articles are central to *Dialogue*'s mission of communicating recent research or analysis on topical energy sector issues in a concise manner to the widest possible audience.

Article submissions should adhere to following criteria:

- Articles should be 3,000 words or less.
- Articles should be submitted in MS Word with text double-spaced on a page size of 8.5 x 11 inches or the metric equivalent.
- The first page should contain the article title, author(s) name(s) and complete affiliation(s), title, and complete mailing address of the person to whom all correspondence should be addressed.
- Footnotes should be numbered consecutively with superscript Arabic numerals and placed at end of article.
- Mathematical expressions should be set in italic type with all equations numbered consecutively on the right hand side of the page.
- Tables should be numbered consecutively. All tables should have concise titles.
- All figures and charts should be numbered consecutively throughout the text. Separate files for each figure and chart embedded in article should be provided as camera-ready copy in a form suitable for reproduction (e.g., jpg format).
- Titling and wording on figures, charts and tables must be 11 point size or larger.
- References should use the author-date citation system and include an alphabetical reference list of all works cited at end of article:
- Style for Book: Chandler, Alfred (1977). The Visible Hand. Cambridge: Belknap Press.
- Style for Report: Federal Trade Commission, Bureau of Economics (1979). The Economic Structure and Behavior of the Natural Gas Production Industry. Staff Report.
- Style for Journal Article: Henderson, J.S. (1986). "Price Determination Limits in Relation to the Death Spiral." The Energy Journal 7(3): 150-200.