IAEE INTERNATIONAL ASSOCIATION FOR ENERGY ECONOMICS

Newsletter

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President's Message

I am pleased to welcome you to this second 2001 issue of the *Newsletter*. We are living in an exiting time relative to the global energy sector and the fundamental changes that are about to take place. In this context it is of vital importance to define the strategy of our own IAEE organization and to define the main targets of our contribution. This is a continuous process going on in the local chapters as well as at conferences and in the Council.

Energy is the largest business in the world. The turnover of the global energy industry amounts to approximately $2 trillion a year. Energy is vital in any economy. The forecast from different sources show a significant increase in energy demand over the next 20 years – specifically in the developing countries and in the countries in transition. At the moment there are several powerful factors combining to shape the future of the energy industry. Liberalisation and market forces, technological innovation and environmental issues are three topics of major importance.

The liberalisation of energy markets will continue in several economies and enhance the efficiency and lower the end user price of energy. During the transition to liberalised energy markets the role of regulators and officials is vitally important and regulators must be willing to trust market forces – if not, it may be better to keep hands away. The California exercise shows that things can get challenging. A question raised has been whether the electricity liberalisation exercise in California will influence other countries to slow down the pace in their own economies? In Europe the European Commission laid the foundation for more competitive markets by the EU Directive on Electricity (1996) and on Gas Markets (1998) and adjustments are moving ahead. There is major restructuring to be expected in both electricity and gas market in Europe in the coming years. The same in other regions of the world.

Technological innovation and improved technological efficiency has been one of the most important factors to increase energy supplies in recent years. There are still significant upsides in improving the efficiency in existing energy systems. In the oil industry improved recovery from existing sources may be equally important as exploring for new sources. Adding to this are exiting developments within fuel cells, solar energy, wind-mill systems, distributed energy systems, bio-systems and other renewable energy systems, which might in the longer run contribute more significantly on the supply side and in addition contribute to environmental challenges.

We should also add the challenge of the fact that the productivity of one-third of the world's people is compromised by lack of access to commercial energy, and perhaps another third suffers economic hardship and insecurity due to unreliable supplies (UN/WEC). This is clearly a big problem for poor countries and energy poverty is a matter of concern for rich countries as well and it is in their interest to help establish a sustainable energy future for all the world's inhabitants.

IAEE contributes to the global energy discussion on all these issues and covers the policy discussions as well as the issues of energy economics, incentives and improved energy efficiency and legal aspects. I believe that it is important for IAEE to take care of the balance between the profound

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Editor's Notes

We're fortunate in having several of the papers presented at the 24th Annual Conference in Houston in late April in this issue. Others will be appearing in the Summer issue. As always, your comments are welcome.

Gale Boyd and John Laitner identify a number of underlying effects that support the possibility that the recent trends in productivity and energy efficiency improvement are the beginnings of a long term trend in the U.S. economy.

Tony Owen shows that if estimates of damage costs

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

understanding of energy economics and the academic contribution on one hand and the policy implication and recommandations for energy strategies on the other hand; to build a bridge between the academic energy institutions around the world and the policy people within the energy business as well as public energy administration. In this context the arenas of our *Newsletter* together with *The Energy Journal* and the regional and international conferences are all important. Furthermore, the IAEE web should be developed further so as to be a source of information and knowledge to the energy communities around in the world.

Arild N. Nystad

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

resulting from the combustion of fossil fuels are internalized into the price of electricity, a number of renewable technologies become financially competitive with coal-fired generation.

Timothy Considine and Andrew Kleit ask whether electrical restructuring can survive given the California experience. Their answer is a qualified "yes", but caution that restructuring efforts should avoid any type of price cap, as much as possible. The situation in Pennsylvania is contrasted with that of California.

Kim Coffman, Vicki Zatarain and Stephanie Gambino describe the new framework developed by the U.S. Materials Management Service for estimating regional economic impacts of oil and gas lease sales. The two-step process of the model is described.

Michael Milligan looks at wind power electricity generation noting that its attributes of clean generation and inexpensive "fuel" are offset by its intermittent and variable nature. However, he comments that both of these can be characterized as different aspects of risk. And risk is something that power companies are increasingly trying to recognize and quantify as electricity markets become more open. He looks at some of the factors related to the operation of, and planning for, wind power plants.

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Future IAEE Events

June 27-29, 2002	25th IAEE International Conference Aberdeen, Scotland *Aberdeen Exhibition and Conference Centre*
October 6-9, 2002	22nd USAEE/IAEE North American Conference Vancouver, BC, Canada *Sheraton Wall Centre Hotel*
June 2003	26th IAEE International Conference Prague, Czech Republic Venue to be Announced

United States Energy Association: Policy Recommendations Summary

The record cold winter and the resulting consumer reaction to rising energy prices, the critical energy shortages that have caused rolling blackouts in California, and the possibility that the situation in California could be duplicated elsewhere, have had one beneficial effect. They have made a diverse group of public and private interests — including policymakers from the president and the Congress on down — aware of the clear need for a national energy policy that will allow all energy providers to more effectively meet the ever growing energy demands of American families and businesses.

Such an energy policy must meet several challenges, including overly burdensome environmental regulations that prevent access to new energy sources; the adverse national security implications of rising oil imports; an energy delivery infrastructure that is aging and increasingly overwhelmed by growing demand; a regulatory process that is often unfair and counter productive; and a lack of foresight in developing new, more efficient energy technologies and alternative energy sources.

The members of the United States Energy Association (USEA) are united in our belief that the time has come to develop a national energy strategy that meets these challenges and also tackles head on the many other critical energy choices we must make. Therefore, we have outlined a strategy that will increase the supply of affordable energy and deliver it to the American consumer in a safe, reliable and environmentally responsible manner. This paper, which was developed after much debate by a broad range of energy interests, outlines that strategy. Specifically we recommend the following steps:

Enhance Energy Supplies

- The nation should encourage energy supply expansion with policies that fully recognize no single source can meet our growing energy needs.
- Current policies should be amended to allow environmentally sound access to domestic resources in order to reduce dependence on foreign supplies, and ensure that American consumers continue to have access to energy at reasonable, affordable prices.
- Tax reform should be enacted to spur capital investment in reliable, affordable and environmentally effective energy technologies and supporting infrastructure.

Encourage Energy Efficiency and Affordable Prices

- Governmental policies should promote energy efficiency.
- There should be free and competitive markets regarding pricing, technology deployment, energy efficiency, and selection of fuels and energy suppliers.
- Funding for the low-income home energy assistance program and weatherization program should be increased.

Stimulate Global Energy Trade and Development

- U.S. leadership in energy development, services and technology should be promoted on a global basis.
- Tax provisions that diminish the international competitiveness of U.S. multinational energy companies by exposing them to double taxation (i.e., the payment of tax on foreign source income to both the host country and the U.S.), and to restrictive anti-deferral rules, should be eliminated.
- Any U.S. foreign policy and development assistance should increase supplies of reliable, affordable and market-based energy for developing countries and countries in economic transition in a way that opens markets to U.S. goods and services, creates cooperative partnerships between the U.S. and overseas energy firms, and enhances international economic and political security.
- The U.S. should foster more open political, legal and institutional structures in developing and reforming countries that facilitate energy trade and investment.
- Federal policymakers should avoid unilateral trade and economic sanctions that exclude U.S. companies from key markets in which foreign-based companies are free to invest.

Promote Energy Technology Development and Long-Range R&D Initiatives.

- Investment in energy technology research and development should focus on energy sources that can realistically expect to have a significant impact in meeting U.S. energy needs over the next 20 to 30 years.

Balance Energy Use and Environmental Concerns

- Government-sponsored education programs should emphasize the importance of energy infrastructure and energy sources as essential to continued economic security and development.
- Government programs intended to advance environmental technologies should measure environmental performance and be available to any energy source that achieves environmental goals rather than favoring selective fuels or technologies.
- The safe and efficient movement of energy goods and services requires significant improvement of the U.S. transportation infrastructure.

Unify the Energy Policy Process

- Rulemaking should promote regulatory predictability to stabilize investment decisions.
- Comprehensive electric industry restructuring should promote efficient competition by encouraging flexible approaches to electricity markets and new investment in transmission and generation.

Recent Trends in the U.S. Energy Intensity: An Index Number Analysis[1]

By Gale A. Boyd and John A. "Skip" Laitner

Introduction

The last 25 years have been a roller coaster ride for energy markets. World oil markets have taken dramatic swings, impacting oil production and consumption patterns. Domestically produced energy resources, natural gas and electricity, have experienced swings in price and consumption patterns in response to changes in technology, regulation, and other energy markets. In recent years, patterns of energy use continue to change. In 1997 and 1998, the economy grew at a rapid rate without a significant increase in energy consumption, even though prices declined. If the growth in the economy was largely in low-energy-using sectors, this decline in intensity could be attributed to a shift in economic activity rather than energy efficiency improvements.

For this paper, we use data from the Energy Information Administration (EIA),[2] the Bureau of Labor Statistics (BLS),[3] and Argonne National Laboratory (ANL) to examine recent trends in energy use, focusing on the relationship between nontransportation energy use and economic activity. We separately examine trends in aggregate, nontransportation electric and fossil fuel use relative to the gross domestic product (GDP). Specifically, we examine trends in the U.S. aggregate *energy/output ratio* or *energy intensity* of the U.S. economy (i.e., the ratio of nontransportation electricity consumption in kilowatt-hour [kWh] or fossil fuel consumption in Btu to GDP). We develop several indices to help explain the changes in these two measures of energy intensity; in particular, we adjust aggregate electric and fossil fuel intensity to account for shifts in the composition of US economic activity. We then examine whether these compositional changes, or *sectoral shift*s, in US economic activity explain the dramatic declines in the ratio of nontransportation energy use to GDP in 1997 and 1998, relative to recent history. The portion of energy intensity that is not explained by compositional changes is labeled *real energy intensity*.

In the late 1980s and 1990s, aggregate energy intensities in the nontransportation portions of the economy declined. This decline was larger and steadier for nonelectric energy than for electricity. Our analysis finds that, for both types of energy, sectoral shift played an important role in the decline. There was an increase in the role of sectoral shift (i.e., a more rapid decline) in 1997 and 1998. This increase in sectoral shift was augmented by a more rapid decline in real energy intensity relative to earlier years, resulting in the large observed drop in aggregate energy intensities.

There are a variety of potential explanations for this apparent change in the behavior of energy use relative to GDP. Rapid overall productivity due to new investment, energy efficient technology that is cost effective despite falling prices, short-term fluctuation in weather-sensitive energy loads, and changes in the mix of economic activities may all have contributed. We focus on measuring the economic mix, but also examine the possible role of the other factors, once we have accounted for the mix of underlying economic activity.

Historical Context

Previous studies have shown that some portion of the changes in aggregate energy intensity may be explained by the relative growth or decline in more energy-intensive or less energy-intensive activities (e.g., shifts from heavy manufacturing to high tech industries and services). When these shifts are accounted for, a clearer picture of the changes in the *efficiency* of the underlying energy-using activities is obtained. Studies of U.S. manufacturing over various years have found that as much as one-third of the decline in energy intensity was due to sectoral shift, with the remainder attributable to improvements in efficiency. Other studies of different countries, sectors, and years have found varying results. For some countries or years, shifts have had little empirical effect.[4] When examining aggregate energy intensity, it is important to account for the impact due to the composition of the underlying energy-using economic activity.

If we look at the very long picture of changing energy intensity (Figure 1), we see how energy use has evolved in the United States. Primary energy use per dollar of GDP (using 1992 chain-weighted dollars) was declining slightly before the energy price increases of the seventies, when the decline accelerated. In the late eighties, energy prices began falling and the decline moderated. For electricity consumption, the trend is quite different. Electricity intensity increased until the mid-seventies. At that time, the increase stopped and intensity declined slightly.

In this paper, we focus on two measures of energy intensity: electricity end use in kWh and nonelectric energy use in nontransportation sectors in Btu, but first we examine long-term trends for several other measures of energy use. Figure 1 shows the ratio of five types of energy use to GDP: (1) primary energy, (2) primary energy less electric end use, (3) nonelectric energy (i.e., primary energy less electric end use and losses), (4) nonelectric energy consumed in nontransportation sectors, and (5) electric end use. Energy prices are also shown in Figure 1.

All measures of energy intensity, except electric end use, show similar patterns after the late seventies but differ in the earlier years. Electric end use intensity follows a quite different pattern, rising at first, then declining only slightly; all other measures fall at various rates over the historical period. If we focus on measures 1-4, we can explain some of the difference in the trend lines. A more rapid decline in nonelectric energy than in primary energy less electric end use reflects the improved efficiency of electric conversion that occurred in the sixties and late seventies; there is little difference in the trend thereafter. Nonelectric energy consumed by nontransportation sectors is quite flat in the sixties and early seventies. This measure follows the general trend of the other measures, but declines more slowly in the eighties than the nonelectric energy intensity with transportation included, when corporate average fleet economy (CAFE) standards had an impact on the transportation component. All four measures of nonelectric energy intensity exhibit a similar, more rapid decline in 1997 and 1998 than in the early

* Gale A. Boyd is with the Argonne National Laboratory and John A. "Skip" Laitner is with the U.S. Environmental Protection Agency. This is an edited version of a paper presented at the 24th Annual International Conference of the IAEE in Houston, TX. See footnotes at end of text.

nineties. A much smaller decline in intensity is in evidence for electric end use intensity.

We focus on the recent trends in intensity for electric and nonelectric less transportation measures in more detail. Since we are effectively removing -transportation sector energy use from our analysis, we use BLS data to adjust GDP by removing commercial (for hire) transportation-related economic activity.[5]

Index Number Analysis of Recent Trends

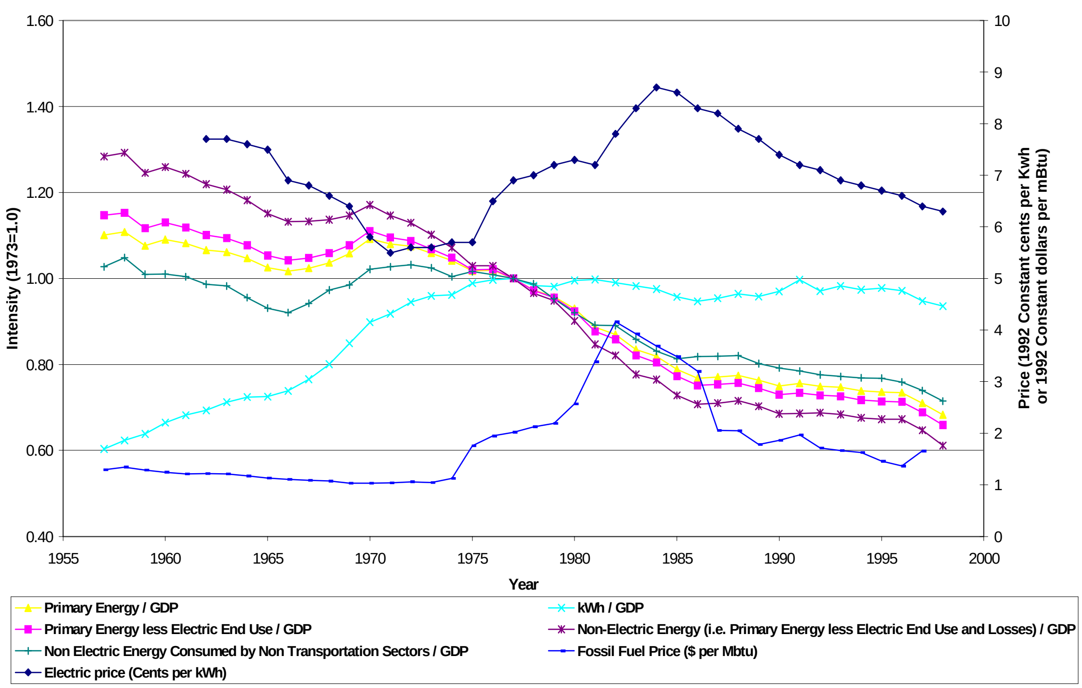
This section presents a decomposition of the electric energy intensities and nonelectric, nontransportation energy intensities from 1983 to 1998. We compute an index of the contribution to energy intensity of the changing composition of economic activity. The remainder is treated as "real" intensity change. Identifiable trends in sectoral change and real intensity are examined. In particular, we look for any departure from recent history in 1997 and 1998.

Electricity/GDP Trends: 1983-1998

The recent drop in electricity intensity occurred during a period of very rapid economic expansion. Using EIA data on electricity sales by sector and BLS data on economic activity, we compute an index of sectoral shift. To examine whether efficiency improvements or economic shifts among individual industrial sectors drove this decline in intensity requires a more detailed accounting of industrial activity than total industrial energy use. Using energy data from the LIEF model, together with BLS data, we disaggregated the industrial sector into 18 separate sectors.[6] A Divisia index of sectoral shift is computed from 1983-1998.[7]

Figure 2 shows the recent trends in electricity efficiency once we accounted for sectoral shifts. Aggregate electricity intensity from 1983-1998 is the same as it was in Figure 1 but is indexed to 1983 instead of 1973. The volatility in electricity/GDP ratio in the late eighties was driven by sectoral shift; specifically, production swings in primary aluminum, steel, and refining.[8] Sectoral shift accounted for about half of the overall –0.3% annual change in energy intensity during the period. Sectoral shift was more stable in the nineties, accounting for nearly all of the slightly higher -0.4% annual intensity change during that period. The average contribution of efficiency improvements remained nearly the same over the entire time period, except in the last three years. In 1995-1998, shift contributed about –0.3% to annual decline, the same as it did from 1990-1999. However, the average rate of real energy intensity change accelerated to –1.1%, compared with an overall rate of less than –0.2%.

Figure 1
Long-Term Trends in Energy Relative to GDP and Energy Prices



Nonelectric Energy less Transportation/ GDP Trends: 1983-1998

A similar analysis was conducted for intensity of nonelectric energy use in the nontransportation sectors. The EIA data does not separate residential and commercial nonelectric energy. To overcome this limitation, a two-sector Divisia index is computed for 1983-1998.[9] The results of this analysis are shown in Figure 3.

The decline in the ratio of aggregate nonelectric energy use to GDP is much larger than that of electricity to GDP, averaging –1.8% annually. When the index of shift is computed, we see that sectoral shift slowed the decline of aggregate energy intensity until 1988 by offsetting some large increases in nonelectric energy efficiency. After 1988, sectoral shift accounted for nearly all (-1.4%) of the annual decline in aggregate intensity (-1.7%). However, in 1997 and 1998, aggregate intensity declined dramatically at –6.0% annually. From 1997 to 1998, sectoral shift caused a -2.7% annual rate of energy intensity, with an additional –3.3% remaining. In the previous 10 years, real intensity had averaged only -0.2% annual change.

Observations on Energy Intensity Changes from 1996 to 1998

Compared with trends in prior years, energy trends in the more recent years looked quite different. The recent years

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showed a marked acceleration of energy intensity decline. If we look back to the point where energy prices took major downward turn (1983 for electricity and 1986 for nonelectric energy), an interesting picture emerges.

During the15-year period of 1983-1998, the rate of aggregate electricity intensity change was -0.3%, about half of which was sectoral shift, and half was real intensity. During 1997 and 1998, electricity intensity changed by an annual rate of –1.8%. Sectoral shift doubled, from –0.13% to –0.26%. After accounting for the sectoral shift, we estimate the decline in real intensity as –1.6%.

For nonelectric energy use in the nontransportation sector, the rate of change in aggregate energy intensity was –1.3% from 1986-1998. Almost four fifths, -1.0%, was sectoral shift; the remainder of the change was decline in real intensity, -0.2%. Between 1996 and 1998, the impact of sectoral shift increased to –2.7%, almost a factor of three. Real intensity declined even more dramatically, to -3.3%.

To understand the significance of changes in 1997 and 1998 from past trends, we should consider the possible underlying economic effects of both the structural shift and the real energy intensity. First, the structural change in the economy toward more value-added, less energy-intensive sectors appears to have increased in recent years. Romm et al. (1999) suggests that the role of the Internet, or information technology (IT) in general, is important. We examine this opinion below in our underlying data. Second, real energy intensity showed some additional reduction relative to past years. There are many reasons that this might have occurred, despite falling energy prices. One reason is that investment as a percent of GDP was up significantly, which may have driven changes in the productivity component of real energy intensity. Another reason may be the success of government-sponsored, voluntary energy-efficiency programs, which may have started to show an impact. On the other hand, we consider that 1997 and 1998 energy use may have been driven by changes in weather-sensitive energy loads. We discuss each of these issues in turn.

Structural Change and Information Technology

The increase in sectoral shift occurred for both electricity and nonelectric energy intensity. The increase and overall magnitude in sectoral shift was much larger for nonelectric energy. This is not surprising, since the difference in sectoral energy intensity was much wider for nonelectric energy than for electric energy. It is the difference in energy intensities between sectors that was the underlying cause of the sectoral shift phenomenon. High value-added information sectors of the economy were much

Figure 2
Decomposition of Electric Energy Intensity

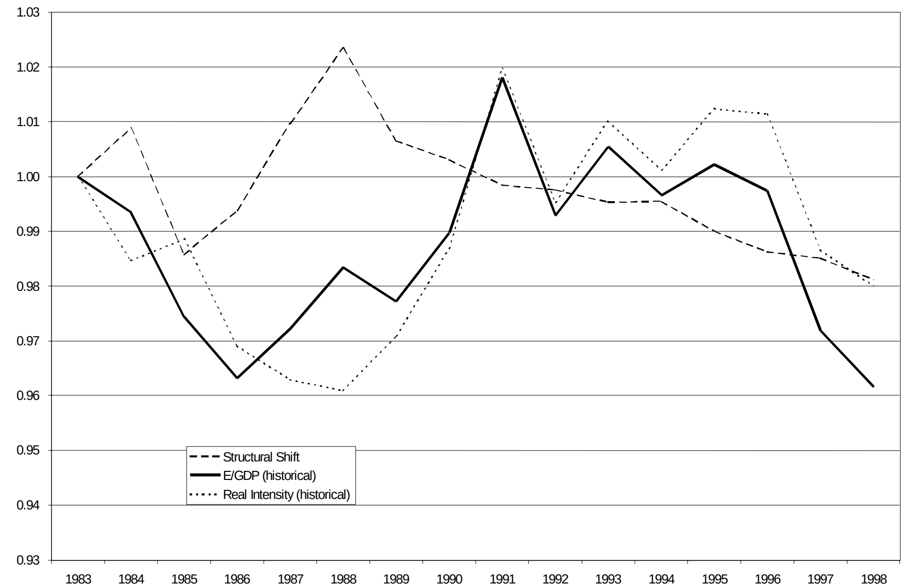


Figure 3
Decomposition of Nonelectric, Nontransportation Energy Intensity

lower in nonelectric energy than electric energy. These sectors grew most rapidly in the last few years.

The growth of the IT sectors has been cited anecdotally as an important driver of change in the U.S. economy. A report by the Department of Commerce (DOC 1999) identifies several IT sectors, many of which are included in the high-growth manufacturing sector taxonomy used in this analysis.[10] To see how these IT sectors may have driven results, we look at the growth rates of the IT vs. non-IT sectors in the LIEF "high-growth" manufacturing sector. We found that the high-growth manufacturing sector grew at an average annual rate of 5.8% from 1983 to 1998. The IT manufacturing component grew at 12% annually. The IT nonmanufacturing component grew at 3.5%, only slightly better than the overall economy (3.0%) and non-IT high growth sector (3.3%) and less than the commercial sector overall (3.6%). It appears that the IT growth strongly influenced the sectoral shift results.

Investment and Productivity

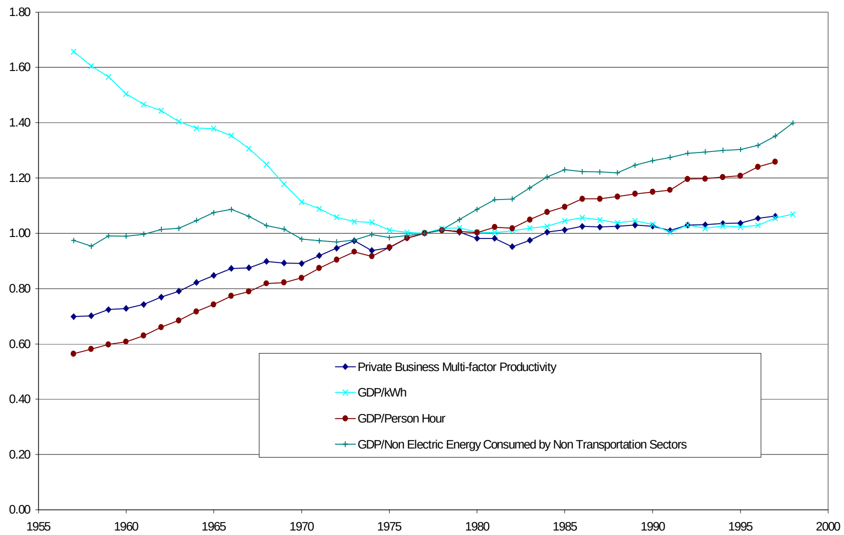
It is well understood that investment in new capital drives the productivity advances in the economy. Since energy intensity, energy per unit of output, is simply the inverse of productivity (measured as output per unit of input of energy or some other resource), it is helpful to examine overall productivity trends in energy and other inputs. Figure 4 shows the aggregate energy intensity measure discussed above represented as productivity measures. These are compared to measures of labor productivity and multifactor productivity (MFP).[11] In recent years, nonelectric energy productivity outpaced labor productivity. On the other hand, we see that electricity productivity was quite close to MFP.

MFP is typically viewed as an economywide measure of technical change. Other things being equal, one would expect single factor productivity to be about equal to MFP. Single factor productivity (e.g., labor or energy) may diverge from MFP if the intensity of other factors, particularly capital, raises the effectiveness of those other inputs. The BLS estimates that increased capital intensity contributed 0.4% to labor productivity between 1990 and 1997 (the last year for MFP data). This contribution compares to 0.5% average in MFP over the same period. Capital deepening, the addition of more capital per unit of labor through increased investment, is an important component of labor productivity. The impact on energy productivity depends on the substitution relationship between energy and capital.

Atkeson and Kehoe (1999) illustrate a "putty-clay" model where energy and capital are long-run substitutes. This view is also consistent with engineering studies of energy efficiency. This view suggests that capital deepening would tend to augment the MFP trend to improve energy productivity. On the other hand, capital requires energy to operate, so the rate of capital deepening would have to be compared to the differences in energy intensity in new capital.

If we simply compare the empirical growth rates from the nineties, we find MFP at about 0.5%; nonelectric and electric productivity, adjusted for sectoral shift, both average only about 0.2%. In the more recent years, we find that MFP was up sharply, averaging about 3.0% in 1994-1996. Energy productivity was also up, averaging 1.0% and 3.3% for electric and nonelectric, respectively. For nonelectric energy, the magnitude of MFP and nonelectric productivity was quite striking. The lower value for electric productivity suggests that capital deepening required additional electric energy use, but that the net effect was still an improvement in energy productivity.

Figure 4
Comparison of Single Factor and Multifactor Productivity Measures



Energy Efficiency Programs

There are many government- and nongovernment-sponsored programs for energy-efficient technologies. These include the Federal Energy Management Program (FEMP), the U.S. Department of Energy (DOE) and U.S. Environmental Protection Agency (EPA) Energy Star Programs, Green Lights, and Climate Challenge Program. In addition, regulatory programs were implemented during the period we examine. We do not provide a comprehensive analysis of these programs but use estimates of the electricity savings from a small group of these programs to illustrate the magnitude of these savings, relative to our measured historical trends.

EPA has estimated the electricity consumption savings from the Energy Star and Green Lights programs. These programs, which began in the early nineties and have focused on the residential and commercial end-use sectors, saved an estimated 26.2 billion kWh in 1998. This amount is almost three times the savings from these programs only two years before in 1996 and about 1.3% of US retail sales of electricity in those sectors. If we plot the contributions of these voluntary program estimates on top of the real electricity intensity, we can see the difference that they began to make

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Trends in Energy Intensity *(continued from page 7)*

(Figure 5). At the same time, other voluntary energy-efficiency programs that showed a strong level of savings. A careful accounting for successes in each of those operations would serve to increase the distance between the actual reduction in electricity intensity and what "would have been."

Short Term Variation Due to Weather-Sensitive Energy Use

The changes in 1997 and 1998 described in this paper might be attributable to short-term fluctuations around a long-run trend. In particular, weather may have driven the year-to-year energy use patterns in a manner consistent with these results. To examine this, we regress the annual growth rates in electric and nonelectric real intensity against the change in heating and cooling degree-days. This approach should capture the weather-sensitive variation in the energy intensity, after our corrections for sectoral shift. Table 1 shows the results (t-statistic shown beneath the coefficient estimates). The intercept is the average growth rate in shift-adjusted energy intensity. The only statistically significant coefficient is for the effect of cooling degree-days on electric intensity, although the heating degree-day variable might be considered "marginally significant". Both variables have the correct sign; and the cooling degree-day is much larger, as expected by the growth in air-conditioning load over the last 15 years. Neither weather variable is significant in the nonelectric equation.

Since the electric intensity equation suggests that some of the variation in the shift adjustment is explained by weather, we wanted to see how well the equation predicts the last two data points. The actual values are –2.5% and –0.6% for 1997 and 1998, respectively. The predicted values are –0.6% and 0.3%, respectively. Collectively, the regression underpredicted the decline in electric intensity in the last two years by 2.8 percentage points. The nonelectric equation actually did a better job of predicting the 1997 and 1998 growth rates of –2.5% and –4.0%. The predicted values were –1.8% and –4.0%. However, the weak t-tests and the counterintuitive sign on the CDD variable suggests that this is not a strong contender to model variations in energy intensity.

Table 1
Regression of Annual Growth Rates in Real Energy Intensity against Changes in Weather (t-ratio shown below coefficients)

		Change	
	Intercept	HDD	CDD
Electric	-0.10%	0.000019	0.000078
	-0.24	1.24	2.04
Nonelectric	-1.38%	0.00003	-0.00006
	-1.49	0.90	-0.68

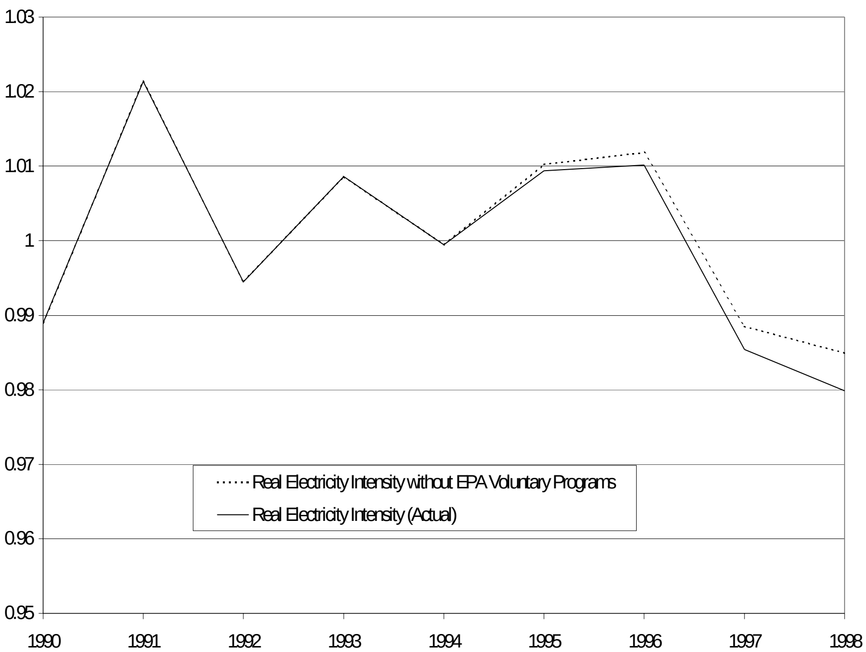

Figure 5
Example Magnitude of Savings from a Few Voluntary Energy Efficiency Programs

Summary

If the economy charts a course toward less energy-intensive forms of economic activity, aggregate energy intensities will continue to fall. It is still too early to tell if the recent years of productivity and energy-efficiency improvements are the beginnings of a long-term trend in the U.S. economy. However, we identify a number of underlying effects that support this possibility. Although we believe that short-term fluctuations in weather did influence the weather-sensitive load (in particular, electricity), changes in heating and cooling degree-days did not adequately explain the change in real intensities. If these short-term, weather-related fluctuations do not explain the changes in energy intensity, then we speculate that rapid productivity improvements embodied in new capital investment may have generated net improvement in energy efficiency. Voluntary programs appear to play a measurable role in U.S. real (adjusted) electricity intensity through efficiency improvements. Although an information-based, service-based, and high-tech economy requires capital investment and uses energy to generate productivity improvements, the shift away from the far more energy-intensive manufacturing sectors has had a measurable effect on the U.S. aggregate energy intensity. At the same time, new and existing technology adoption is being accelerated in the buildings and offices of the same service and high-tech companies. If these effects continue, then recent trends in energy intensity may continue as well.

Footnotes

[1] This work is sponsored by the Office of Atmospheric Programs, U.S. Environmental Pro-

tection Agency, under contract No. W-31-109-ENG-38. We would like to thank Howard Gruenspecht, Joe Romm, and Lee Schipper for their helpful comments on an earlier draft of this paper.

[2] Energy Information Administration (1999).

[3] Andreassen and Chentrens (1999).

[4] For an early reference on the U.S. manufacturing sector, see Boyd et al. (1987). Greening et al. (1997) compares several methods for analyzing structural shift for 10 OECD countries.

[5] We cannot remove transportation activity in firms that own and operate internal vehicle fleets, only activity such as that associated with for-hire trucking, rail transportation as a flow of services is not included in GDP, so no adjustment is required for those activities.

[6] LIEF refers to the Long-Term Industrial Energy Forecasting model (Ross et al. 1993).

[7] See the appendix for technical details on the index number approach.

[8] These sectors exhibited very volatile patterns in the eighties. For example, the annual growth rate in the aluminum industry was –55% in 1985 and 44% in 1987. Although not as dramatic as aluminum growth rates, annual growth rates in steel and refining ranged from –21% to 28% in the late eighties and very early nineties.

[9] See appendix for details.

[10] Some of the "IT producing sectors" identified in the DOC report are communications and broadcasting, which we assign to the commercial sector, not manufacturing.

[11] Data shown are for private, nonfarm business.

[12] The term "rolling year" index is introduced by Lui to represent an annual, year-to-year, chain-weighted index rather than one that always references a base year, 0, and current year, T. This is the same index frequently employed by earlier authors but called simply a Divisia index (e.g., Boyd et al. 1987).

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Appendix: Index Number Methodology

By using the terminology introduced by Lui et al. (1992), we computed a rolling year Divisia index.[12] of the component of aggregate energy intensity that was due to sectoral mix for the years that the data were available. This index is given by:

$$(1+\Delta I_{mix})_{T-1,T} = \exp \sum_{j=1,J} \tfrac{1}{2}\left(\frac{E_{j,T-1}}{E_{T-1}} + \frac{E_{j,T}}{E_T}\right)\ln\left(\frac{S_{j,T}}{S_{j,T-1}}\right)$$

$$S_{j,T} = {Y_{j,T}}/{Y_T} \qquad (1)$$

where J is the total number of sectors. Energy use and output are denoted by E and Y, respectively. For simplicity we suppress any subscripts on E, although indices for electricity and non-electric energy are both computed. The index of total, or aggregate energy intensity is computed by:

$$(1+\Delta I_{total})_{T-1,T} = 1+\ln\left(\frac{E_T/Y_T}{E_{T-1}/Y_{T-1}}\right) \qquad (2)$$

The real intensity is computed by the identity:

$$(1+\Delta I_{total})_{T-1,T} = (1+\Delta I_{mix})_{T-1,T}(1+\Delta I_{real})_{T-1,T} \qquad (3)$$

It is well known that many index number approaches, including the one used here, suffer from a residual term. The index of real intensity derived from the identity in (3) would include this residual, so might not be an accurate measure. Ang and Choi (1997) propose a refined Divisia index, the Log Mean Divisia (LMD) index, which does not have this problem. The LMD was applied to the data used in this paper and the differences between the methods were empirically inconsequential. The rolling year Divisia results are reported.

The Economics of Renewable Energy Technologies in the Context of Australia

*By Anthony D. Owen**

Introduction

Despite the apparent environmental attractiveness of renewable energy, excluding hydropower its market penetration has been limited to date relative to past projections. This failure has not, however, been due to any failure in its anticipated reduction in cost. For all major renewable technologies, future cost projections for successive generations have either agreed with previous projections or have been even more optimistic. Their lack of commercial success has in large part been due to declining fossil fuel prices for conventional technologies, combined with energy market reforms that have tended (at least in the short run) to return substantial cost savings for utilities utilizing these technologies. Global environmental concerns over emissions of carbon dioxide, however, are likely to exert significant pressure on governments in industrialized countries to encourage power generation by means of more environmentally benign technologies and micro-power supply sources.

It is widely recognised that one of the most important barriers to the large-scale exploitation of renewable energy technologies is related to their relatively high initial capital cost as compared with conventional generation, transmission and distribution networks[1]. The latter have often benefited from loans at favourable interest rates with extended repayment periods, whereas renewable energy technologies (particularly those best suited to distributed rather than centralised use) must raise capital privately at prevailing market rates. Although capital costs have decreased with market penetration, technological development, and economies of scale, and running costs are generally relatively low, it is estimated that, under current market conditions, most renewable technologies will not be able to compete with conventional ones before the middle of the current century. However, these financial viability comparisons are based upon costs that generally ignore environmental externalities associated with the combustion of fossil fuels. Results from the ExternE project conducted recently in the European Union (1998) show that external cost estimates may significantly change the current perception about the economic attractiveness of different energy sources and has stimulated a vigorous debate on the potential exploitation of the resulting figures in energy decision making.

This article specifically addresses externalities associated with electric power generation, arising from both renewable and non-renewable sources. It focuses on emissions of carbon dioxide (CO_2) and their imputed environmental costs since, being global in nature, such costs can be considered to be uniform per unit of emissions across all countries (even though ultimately the costs/benefits to individual countries resulting from the accumulation of such emissions may vary greatly). The data relate to Australian conditions, but the conclusions should have must broader implications.

Environmental Externalities in Power Generation

Externalities are defined as benefits or costs generated as an unintended by-product of an economic activity, that do not accrue to the parties involved in the activity. Environmental externalities are benefits or costs that manifest themselves through changes in the physical-biological environment.

Pollution emitted by fossil fuel fired power plants during power generation may result in harm to both people and the environment. In addition upstream and downstream externalities, associated with securing fuel and waste disposal respectively, are generally not included in a utility's costs. To the extent that the electricity industry does not pay these environmental costs, or does not compensate people for harm done to them, consumers do not face the full cost of electricity they purchase and thus energy resources will not be allocated efficiently.

The two principal methods for assessing the value of externalities are calculation of damage costs and calculation of control (or mitigation) costs.

Estimation of damage costs involves assessment of four factors: emission quantities, emission concentrations at receptor points or areas, the physical effect of those concentrations on that point, and the economic value of those effects in terms of willingness to pay to avoid damage arising from the emissions. All four factors are subject to significant uncertainty.

Control costs are generally used as a surrogate for damage costs as they are easier to estimate. The implicit assumption in control costing is that society controls pollution until the benefits of additional controls would be outweighed by the costs. Generally control costs are viewed as a poor substitute for estimating damage costs, although when derived as a function of a market in emission permits, at least in theory, they yield a minimum cost solution for compliance in reaching a set target (although the actual cost of achieving this target will only be known ex poste).

For simplicity, externalities of fossil fuel combustion can be divided into three broad categories:

- hidden costs borne by governments, including tax subsidies, direct energy industry subsidies, and support of research and development costs;
- costs of the damage caused to health and the environment by emissions other than CO_2; and
- the costs of global warming attributable to CO_2 emissions.

The second category is costs due to emissions that cause damage to the environment or to people. These include a wide variety of effects, including damage from acid rain and health damage from oxides of sulphur and nitrogen from coal fired power stations. Other costs in this category are power industry accidents, whether they occur in coal mines, on offshore oil or gas rigs, in nuclear plant, on wind farms, or at hydro plants.

The third category refers to external costs due to greenhouse gas emissions from electricity generating facilities that

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[1] See footnotes at end of text.

cause global warming with all its associated effects. This is a very contentious area, and the range of estimates for the possible economic implications of global warming is huge. Costs associated with climate change, flooding, changes in agriculture patterns and other effects all need to be taken into account. However, there is a lot of uncertainty about the magnitude of such costs, since the ultimate physical impact of enhanced levels of global warming has yet to be determined with precision. Thus, deriving monetary values on this basis of limited knowledge is, at present, an imprecise exercise.

Energy Subsidies

Support that lowers the cost of power generation can take many forms, including support to the use of inputs (e.g., water, fuels, etc.), public financing at interest rates below the market value, tax relief on corporate income, lump sum support to fixed capital investment in research and development, etc. Examples include the exemption of government-owned electricity generators from corporate income tax payments (increasing the relative after tax rate of return compared with electricity generation by private enterprises) or the provision of loans at interest rates well below market rates, or over repayment periods in excess of market terms (which favour capital intensive energy forms, such as nuclear and coal, and encourages over-investment).

It is not the purpose of this paper to examine the full range and costs associated with energy subsidies world-wide, but their adverse impact on global emissions of CO_2 has been, and remains, significant (see Mountford (2000) and Schneider and Saunders(2001)).

Emissions Other Than CO_2

Among the major external impacts attributed to electricity generation are those caused by air pollutants, such as particulates, sulfur dioxide (SO_2) and nitrogen oxide (NO_x). Table 1 gives emissions of these, and other, pollutants from a typical 2000 MW fossil-fuel power station. Emissions of SO_2 and NO_x have long range transboundary effects, which makes calculation of damages an imprecise exercise. Such calculations require measurement to be based upon the unique link between fuel composition, characteristics of the power unit, and features of the receptor areas. Thus estimated damage costs vary widely across countries. For example, for member countries of the European Union, damage costs arising from power plant emissions of SO_2 range from Euro 1,027-1,486/tonne for Finland[2] to Euro 11,388-12,141/tonne for Belgium.

The External Damage Costs of Emissions of Carbon Dioxide

Table 2 gives life-cycle CO_2 emissions (in tonnes per GWh) of the major forms of electric power generation. From this table it is evident that CO_2 emissions from coal and oil-based technologies far exceed those of the “renewables” and are twice those of gas.

The European Commission (1998) has calculated an indicative 95% confidence interval for damage costs arising from CO_2 emissions (from all sources), with limits of Euro 3.8/tonne CO_2 and Euro 139/tonne CO_2. “Base case” estimates were Euro 18/tonne CO_2 and Euro 46/tonne CO_2 (or approximately A$33/tonne and A$85/tonne respectively at current exchange rates).

These cost bands are relatively wide, and the corresponding “damage” per MWh is, therefore, of a corresponding dimension. Combining these “base case” cost estimates with the data contained in Table 2 yields base case “damages”, from CO_2 emissions alone, from conventional coal fired plant in the range of A$32/MWh up to A$82/MWh

Table 3 gives current costs (in A$/MWh) of electricity generation by both renewable and non-renewable technologies. From this table it is clear that, depending on the value within the range that is chosen, coal may either lose a major cost advantage or be rendered financially non-viable with respect to some renewable technologies (and in particular wind and biomass) if CO_2 emission damages alone were to be internalised into production costs. With respect to gas, coal’s current (small) cost advantage would be lost entirely.

(continued on page 12)

Table 1
Emissions from Typical 2000 MW Fossil-fuel Power Station

Pollutant	Conventional Coal (tonnes per year)	Conventional Oil (tonnes per year)	Combined-cycle Gas (tonnes per year)
Carbon dioxide	11 million	9 million	6 million
Sulphur dioxide	150000	170000	Negligible
Nitrogen oxides	45000	32000	10000
Airborne particulates	7000	3000	Negligible
Carbon monoxide	2500	3600	270
Hydrocarbons	750	260	180
Hydrochloric acid	5000-20000	Negligible	Negligible
Solid waste and ash	840000	Negligible	Negligible
Ionising radiation (Bq)	10^{11}	10^{9}	10^{12}
Trace elements		Depends on source	

Abbreviation: Bq Becquerel
Source: IEE (1993)

Table 2
CO_2 Emissions from Different Electricity Generation Technologies

Technology	CO_2 Emissions (tonnes per GWh) Fuel Extraction	Construction	Operation	Total
Coal-fired (Con)	1	1	962	964
AFBC	1	1	961	963
IGCC	1	1	748	751
Oil-fired	-	-	726	726
Gas-fired	-	-	484	484
OTEC	N/A	4	300	304
Geothermal	<1	1	56	57
Small hydro	N/A	10	N/A	10
Nuclear	~2	1	5	8
Wind	N/A	7	N/A	7
Photovoltaics	N/A	5	N/A	5
Large hydro	N/A	4	N/A	4
Solar thermal	N/A	3	N/A	3
Wood (SH)	-1509	3	1346	-160

Abbreviations:

AFBC	Atmospheric Fluidised Bed Combustion
BWR	Boiling Water Reactor
Con	Conventional
IGCC	Integrated Gasification Combined Cycle
OTEC	Ocean Thermal Energy Conversion
SH	Sustainable Harvest

Source: IEA (1989)

Economics of Renewable Technologies *(continued from page 11)*

Although the majority of US State utility commissions currently take environmental externalities into consideration in their resource planning process, only seven have explicitly specified monetary externality values for designated air emissions from power plants. Such values form part of the utilities "Integrated Resource Planning" (IRP) process, and are not actually internalised into their power pricing structures. The values (all in 1992 dollars) are largely based upon "control" costs, with ranges reflecting differing ideas over the extent of such costs. For example, the Massachusetts figure is based upon the marginal cost of planting trees in order to sequester carbon. The Oregon range represents U.S. Department of Energy "low" and "high" estimates.

California	US\$9/ton CO_2
Massachusetts	US\$24/ton CO_2
Minnesota	US\$5.99-13.60/ton CO_2
Nevada	US\$24/ton CO_2
New York	US\$8.6/ton CO_2
Oregon	US\$10-40/ton CO_2
Wisconsin	US\$15/ton CO_2

In a study incorporating three of these States, the U.S. Department of Energy (EIA, 1995) concluded that "The requirement to incorporate externalities in the resource planning process had negligible impacts on the planned resource mix of the utilities in each of the three States."

Making allowances for inflation since 1992, and adjusting the units of measurement, these figures would (roughly) correspond to the range derived by the EU. However, it should be emphasized that only external damage costs associated with emissions of CO_2 have been considered here. Those associated with other forms of environmental degradation must also be estimated in order to achieve a reasonable balance across the range of power generating technologies, both renewable and non-renewable.

Internalising the Externalities

The leading renewable energy technologies are characterised by relatively high initial capital costs per MW of installed capacity, but very low running costs. This structure can make renewable technologies financially unattractive compared with traditional fossil fuel derived power using traditional project evaluation techniques based upon the anticipated life of the electricity generating facility (say, 30 years). However, in terms of an economic/environmental evaluation, the relevant time frame should be set by the date at which all of the consequences attributable to the project had ceased to exist. In the context of CO_2 emissions from fossil fuel power stations this period could exceed 100 years. Further, it is likely that the value of emission reduction will continue to rise into the future given projected world population growth, economic growth, and the subsequent difficulties in meeting global climate change agreements. In this context, the rate of discount is crucial in assessing the relative cost and benefit streams of alternative energy technologies.

It has been argued that for intergenerational damages (i.e., damages caused by the actions of one generation that affect another generation) individual time preference is

Table 3
Cost of Renewable Energy Technologies – Current and Expected Trends (Australian 1998 dollars)

Energy Source	Technology	Cost $/MWh*	Expected trend	Comments
Coal	Coal-fired steam	30-40	Stable	
Gas		35-60	Small decrease	
Solar radiation	Solar hot water	40-70[1]	↓20% with increase in market size	Typical domestic system cost is $2000
	High temperature solar thermal	70-190	Longer term cost ↓ expected with mass production	
	Solar thermal electric	200-270	Cost may halve by 2010	
	Photovoltaics PV RAPS	300-500 350-600	↓ 50+% by 2010	
Wind	Wind turbine/generator Wind RAPS	90-120 150-400	↓ to 75% of current cost by 2005 ↓ 15 to 30% by 2010	Site (wind resource) variation is reason for the range in costs
Fuel wood	Boiler	70-110		
	Pyrolysis furnace	0.45-0.85/litre		Cost assumes biomass is provided at a cost of between $20 and $50 per tonne
Bagasse	Boiler (cogeneration)	40-50	Slight reduction	Also embedded generator network cost savings
	Gasification	30-100[2]	Energy costs expected to ↓ with ↑ in efficiency	
Various wastes	Boiler (cogeneration)			
	Gasifier/gas engine	80-200[2]	25% ↓ expected by 2010	
Suger, starch, cellulose	Hydrolysis/fermentation/distillation	$0.28-$0.69/litre	Competitive with oil by 2010	Worldwide the cost of production from sugar & starch has ↓ 50% over past 10 years
Organic wet waste	Biogas digestor/gas engine	30-200	↑ beyond 2005	Economics depend on negative cost of fuel and value of by-products
Landfill gas, Sewage gas	Gas Engine	55-90	No change to 2010	Most of resource recoverable at $65/MWh
Hydro	Hydro turbine/ generator Micro hydro RAPS	40-100 70-250	↑ as most attractive sites are used. Remain constant	Cost is very site specific
Geothermal hot dry rock	Heat exchanger/ turbine	90-130	Unknown	Speculative technology, costs are rough estimates. Cost also site dependent
Tides	Low head hydro turbine/generator	80-150	No change	Very site specific
Waves	Various devices/ generator	100-200[2]		

Source: DISR (1999)

* unit is MWh except where specified otherwise

1. Cost of delivered energy from the solar component of a solar hot water system. Calculation based on the installed capital cost differential between the solar unit and competing unit of $1500.

Economics of Renewable Technologies *(continued from page 12)*

irrelevant. It follows that a discount rate equal to the per capita growth rate is appropriate, which would probably lie between 1% and 3%. In addition, without assumptions regarding the preferences of future generations, adjusting future cost and benefit streams to reflect such changes would be a very subjective action. Nevertheless, benefits of CO_2 emission reductions are likely to increase (in real terms) over a significant part of the current century, given the long time lags inherent in the breakdown of CO_2 in the atmosphere.

Once monetary values have been derived to reflect the external costs of differing technologies, the next step is to devise a mechanism for "internalising" them into market prices. In theory, an energy tax would represent a relatively straightforward solution, although the practicalities of its imposition would be fairly complicated. The tax would be required to be imposed at differential rates, depending upon the total estimated damages resulting from the fuel in question. A simple carbon tax alone, for example, would not impose any cost on the nuclear power industry. The tax would also have to be imposed by all nations, to ensure that the competitiveness of their industries in global markets was not compromised. The resulting tax revenue would also have to be distributed in such a way that implicit energy subsidies were not introduced. Finally, the worst of any social impact of energy taxes on poorer sections of society would have to be offset to insure that the tax burden was not disproportionate in its incidence.

An alternative approach to the problem of reflecting external costs, and one that would possibly cause less economic disturbance, would be to introduce "environmental credits" for the uptake of renewable energy technologies. Examples are currently commonplace. However, such credits do not "internalise" the social costs of energy production but rather subsidise renewables. In addition, the taxpayer pays the subsidy and not the electricity consumer, thus rejecting the "polluter pays principle".

Conclusions

On the basis of CO_2-imposed externalities alone, it has be shown in this article that estimates of damage costs resulting from combustion of fossil fuels, if internalized into the price of the resulting output of electricity, would clearly render a number of renewable technologies (specifically wind and biomass) financially competitive with coal-fired generation. However, gas-fired power generation would clearly have a marked financial advantage over both coal and renewables under current technology and market conditions. The internalization of other environmental externalities has not been addressed in this article, but it is evident from Table 1 that including costs associated with power station emissions of sulfur dioxide and nitrogen oxides would further strengthen the competitive position of renewable technologies. In addition, over the next couple of decades, the cost of renewable technologies (particularly those that are "directly" solar-based) is likely to decline markedly as technical progress and economies of scale combine to reduce unit generating costs. Incorporating environmental externalities explicitly into the electricity tariff would serve to hasten this process.

These results are specific to Australia, where electricity generated by coal-fired power stations is, by world standards, relatively cheap (largely due to Australia's large endowment of domestic coal resources, institutional factors relating to past financing practices for government-owned power stations, and recent electricity industry re-organization). Nevertheless, the principle of internalizing the environmental externalities of fossil combustion is of global validation. Whether this is achieved directly through imposition of a carbon tax or indirectly as a result of ensuring compliance with Kyoto targets, a similar result is likely to be achieved; i.e., a rise in the cost of power generation based upon fossil fuel combustion and a relative improvement in the competitive position of an increasing range of renewable energy technologies.

Footnotes

[1] See Watt and Outhred (2001) for a detailed analysis of market impediments facing renewable energy technologies.

[2] The data for Finland underestimate damages due to lack of data from non-European receptor points.

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Abstracts should be between 200 and 1000 words. At least one author from an accepted paper must pay the registration fees and attend the conference to present the paper. All abstracts and inquiries should be submitted to: Professor Alex Kemp, University of Aberdeen, Department of Economics, Edward Wright Building, Dunbar Street, Old Aberdeen, AB24 3QY. Tel: 44 (0) 1224 272168, Fax: 44 (0) 1224 272181, email: a.g.kemp@abdn.ac.uk.

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Should States Restructure Their Electricity Sectors? Lessons from California and Pennsylvania

*By Timothy J. Considine and Andrew N. Kleit**

Five years ago restructuring efforts in several states promised to unshackle electricity firms from the dead hand of regulation, creating efficiency gains and price reductions similar to those experienced in transportation, telecommunications, and other deregulated industries. Today, with the ongoing problems in California, restructuring is no longer perceived as a panacea. In this brief essay, we discuss the motivation behind restructuring, the course of restructuring in California and Pennsylvania, and the lessons learned from these two states.

Why Restructure?

Oddly enough, proponents of restructuring have a difficult time articulating why restructuring is a good idea, beyond ideological references to the efficiencies of free markets. There are two basic motivations for the recent wave of restructuring.

First, restructuring frees electricity generators from rate of return regulation. Generators thus have important incentives to cut costs, which will result in lower prices for consumers in the long run. Moreover, in areas with excess capacity, competition will naturally decrease the price of power.

Second, restructuring eliminates the monopoly on retailing held by local distribution companies. In a properly restructured market, any number of providers can compete on both price and quality of service when offering retail electricity to consumers.

We shall argue that policies designed to recover stranded costs actually impede competition at the retail level. Stranded costs are the non-remunerative investments electric utilities made in generation capacity during the regulated era. The compromises that enabled passage of restructuring legislation allowed utilities to recover their stranded costs in return for retail price ceilings during this transition period. These ceilings, however, interfere with the effective operation of a retail market for electricity.

The California Experience

The details of the California restructuring plan are well known, so only a brief description will be made here. Generators were deregulated and, for market power reasons, incumbent producers were required to sell off half of their generation capacity. The restructuring plan required most power to be bought and sold in a wholesale power exchange called "POOLCO," based on one previously used in Britain. Beginning January 1, 1998, residential customers of the investor owned utilities received a 10 percent reduction in their monthly bills. Consumer rates include a distribution and transmission charge, a generation charge, other miscellaneous charges, and a competitive transition charge (CTC) that was used to pay off stranded costs. For example, a customer of Southern California Edison on average paid 12.7 cents per kilowatt hour in 1999 (see Table 1). More than 4.6 cents of that reflected a still-regulated transmission and distribution charge. The generation charge was approximately 3.2 cents. Other miscellaneous charges amount to a shade over 2.3 cents. The CTC picked up the remainder, 2.5 cents per kilowatt hour. Consumer rates were frozen until stranded costs were paid off.

Table 1
Average Electricity Rates for Southern California Edison Co., 1998-2001

	Average rate in cents per kilowatt hours			
Component	**1998**	**1999**	**01/2000-04/2000**	**05/2000-02/2001**
Generation Charge	3.34	3.22	3.78	17.36
Transmission & Distribution	3.34	4.64	5.66	3.44
CTC	3.28	2.50	1.18	-10.11
Other Charges	2.76	2.31	2.10	2.17
Amount paid per month	**12.72**	**12.67**	**12.72**	**12.86**

Note that the CTC charge is a residual set equal to the fixed price to consumers minus transmission, distribution, and other charges, and minus the fluctuating generation price. As long as the generation price did not go "too high" the CTC would remain positive, and the system would be financially stable.

In this system, generators have important incentives to cut costs, one of the two objectives of restructuring. But where did this leave retailing? In the California system, retailing was left absolutely nowhere. Any consumer who chose to purchase power from a retailer other than the local distribution company received a rebate equal to the POOLCO price. This meant that a retailer could not show a profit unless it was able to purchase power below the POOLCO price for power, which was close to impossible. For example, if the POOLCO price was 3.5 cents per kilowatt-hour, 3.5 cents was the amount of the rebate. Since no one would sell to retailers at less than 3.5 cents when they could get this amount in the POOLCO market, no electricity retailer could make money in California. Thus, the California system precluded retail competition until stranded costs were paid off.

Unfortunately, by the summer of 2000, the California system unraveled. The chief culprit was the lack of electricity supply. For over a decade, it had been extremely difficult to site new power plants in California. The state had become highly dependent on hydroelectric sources, power from natural gas plants, and imported power. In the summer of 2000 lack of rain and snow from the previous winter greatly reduced the availability of hydroelectric resources. Rising natural gas prices also increased the cost of gas-fired generation, which provides more than forty percent of the total generation capacity in California. Perhaps combined with the exercise of market power by suppliers, the result was a price explosion. The wholesale price of electricity rose over ten fold.

Distribution companies, with their retail prices fixed by law, saw their generation prices not only drive their CTC to zero, but negative, eating up their existing equity base. The

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problem was further exacerbated by the requirement that distribution companies buy their power on the spot market through the POOLCO. Distribution companies, unable to shield themselves against price risk though the use of long-term contracts, and unable to raise retail rates because of regulation, had to suffer the full financial exposure of the price increase.

By January 2001, the major distribution companies in California were essentially bankrupt. Power generators refused to sell these companies power for fear of non-payment, and widespread blackout resulted. The state of California stepped in, eliminated the POOLCO, and subsidized electricity markets, at a cost of approximately $40 million per day. At this writing, the state is only now beginning to raise electricity prices.

Restructuring did not cause the power supply shortage in California. But the form of restructuring – with generators and distributors essentially required to buy on the spot market – exposed them to the risk of using spot markets. The regulated retail prices meant that distribution companies held all the risk. When prices exploded, bankruptcy and blackouts were the natural response. The state of California, by not allowing prices to rise, at least at this point in time, is only exacerbating the problem.

The Pennsylvania Experience

The Pennsylvania restructuring plan was similar to the California plan in several ways. Generation was freed from rate of return regulation, and power was sold in a largely unregulated market. Generation divestitures were not required, though many took place voluntarily. Prices to consumers were lowered 10 percent, and capped for the period of stranded cost recovery. Again, prices to consumers were set as a total of transmission, distribution, generation, and CTC charges (see Table 2).

Table 2
Average Electricity Rates for Selected Pennsylvania Utilities, 1999

	Rate in cents per kilowatt hours		
Component	**PECO**	**GPU**	**Allegheny**
Generation Charge	5.75	4.00	3.22
Transmission & Distribution	4.57	3.03	3.06
Transition Charge	1.82	0.73	0.64
Amount paid per month	**12.14**	**7.76**	**6.92**

There were, however, two important differences from the California structure. First, power could be sold on a spot or long-term basis, whatever the parties thought was in their best interest. Second, consumers choosing a supplier other than their local distribution company were given "shopping credits" set administratively by the state Public Utility Commission. Shopping credits were set originally above the generation cost component of retail prices, which allowed retailers to enter the market.

Electricity retailers did enter the market, selling at one point up to 10 percent of customers. Of special significance is the success of Green Mountain Power, which has sold environmentally friendly power to customers at a premium price. Unfortunately, as market prices have risen (and shopping credits remained fixed), retailers have been squeezed out of the market.

Wholesale electricity prices have risen in Pennsylvania in the last two years by approximately 25 percent. Power in Pennsylvania comes largely from coal-fired generators, with natural gas plants representing only the marginal suppliers. New power plants are being allowed into the system, though the required administrative and regulatory procedures slow this process down.

The Pennsylvania price cap, just like its California equivalent, does create the possibility of a market meltdown if wholesale prices rise too high. But that has not happened, and is not likely to. The supply of power in Pennsylvania is very stable, and is not highly dependent on the price of natural gas and on natural factors, such as the amount of rainfall. Summer peaking prices can get very high, but only for relatively short periods of time.

Can Electricity Restructuring Survive?

The California experience brings clear lessons. If power markets are going to be restructured, retail prices must be allowed to reflect the opportunity cost of power. Further, if restructuring is about allowing contractual freedom, power should be allowed to be sold in any form trading parties choose, not just on the spot market.

The Pennsylvania example shows that electricity restructuring can survive, and survive with some success. But one issue that comes out of both California and Pennsylvania is the failure of retail suppliers to enter the market, and to survive there. We suggest that this is in large part due to price caps required by regulators in both states. Potential retailers must compete against a regulated price that greatly limits their profit opportunities. Only when price caps are eliminated in Pennsylvania do we expect to see a burgeoning retail market for power.

Should other states restructure? We suggest that the answer is a qualified, " yes". But restructuring efforts should avoid as much as possible any type of price cap. In addition, advocates of restructuring should understand that generation efficiencies and a robust retail market take time to evolve.

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The New Regional Economic Impact Modeling Approach for the U.S. Minerals Management Service

*By Kim F. Coffman, Vicki Zatarain and Stephanie Gambino**

Introduction

The U.S. Minerals Management Service (MMS) is responsible for managing mineral resources on the Federal Outer Continental Shelf (OCS). Among the many factors decision makers must consider prior to scheduling and conducting OCS oil and gas lease sales (auctions of development rights) are the magnitude and location of economic impacts on local communities. In the late 1990s, MMS developed a new framework for estimating regional economic impacts that recognizes regional differences but provides for a consistent approach to the development of models for all coastal areas and for different levels of analysis. This paper presents a general description of that framework and the models themselves, focusing on models for Gulf of Mexico (GOM) analyses. For more details on the various activities that comprise an offshore oil and gas project,[1] the resulting expenditures, and the allocation of those expenditures to specific industrial sectors in designated onshore economies, see the papers by David Dismukes & Williams Olatubi and by Jonathan Skolnik & Chris Holleyman in the proceedings for the April 2001 IAEE International Conference.

Background

Legal Mandate

The OCS Lands Act, as amended, established a policy for the management of oil and natural gas on the OCS and for protection of the marine and coastal environments. The mandate given MMS under the OCS Lands Act and other laws, is essentially

- to expedite exploration & development of the OCS;
- to protect human, marine, & coastal environments;
- to obtain for the public a fair & equitable return on OCS resources;
- to preserve & maintain competition; and
- to balance this range of objectives under all market conditions.

Regional economic impact analyses play a part in two kinds of planning to help carry out this mandate. The first is the development of a new 5-year program (a 5-year schedule of proposed auctions of mineral rights, which are called lease sales). The OCS Lands Act requires that a 5-year program be in place and lays out a variety of considerations and requirements for developing one. After a 5-year program has been approved, and prior to each lease sale, MMS conducts more detailed analyses for decision makers, who then decide whether the sale will be held as proposed, modified, delayed, or cancelled.

The regional economic impact analyses conducted in these planning phases help satisfy two primary statutory requirements. Section 18 of the OCS Lands Act requires that, in the development of a 5-year program, the

> [t]iming and location of exploration, development, and production of oil and gas among the oil- and gas-bearing physiographic regions of the outer Continental Shelf shall be based on a consideration of … (B) an equitable sharing of developmental benefits and environmental risks among the various regions … . [43 U.S.C. 1344(a)(2)]

The equitable sharing analysis, which examines all coastal areas near lease sale areas on a proposed schedule, is included in the decision document for each of three stages in the development of a new 5-year program.

In addition, the National Environmental Policy Act (NEPA) of 1969 states that

> [t]he Congress authorizes and directs that, to the fullest extent possible: … (2) all agencies of the Federal Government shall … (C) include in every recommendation or report on a proposal for legislation and other major Federal Actions significantly affecting the quality of the human environment, a detailed statement by the responsible official on (i) the environmental impact of the proposed action, … . [42 U.S.C. 4332]

To this end, MMS prepares Environmental Impact Statements (EISs) and Environmental Assessments (EAs); acquires marine environmental data; analyzes data, literature surveys, socioeconomic studies, and special studies; and holds public conferences. The EIS for a proposed 5-year program contains a regional impact analysis for each coastal area throughout the Nation near a sale on the proposed schedule, while the EIS for an individual lease sale includes an analysis for the local coastal areas.

Application of Regional Economic Impact Analyses to MMS Mandate

However they measure regional economic effects of new investments or activity, such as OCS oil and gas development, regional economists generally classify the effects as direct, indirect, or induced. For the equitable sharing and EIS analyses, direct effects are those resulting from the first round of "new" spending by companies working directly on an OCS project(s). Indirect effects result from the additional project-related spending of contractors, vendors, and others who provide goods and services to the companies working directly on the OCS project(s). Induced effects result from the additional consumer spending by employees (and their families) of the businesses working directly on, or providing goods and services in support of, the project(s).

The MMS bases all its analyses of proposed lease sales, not just those of regional economic impacts, on Exploration and Development (E&D) Scenarios. The appropriate MMS regional office's Resource Evaluation unit prepares an E&D scenario for each sale or schedule of sales. The E&D scenario consists of estimates of the amount of infrastructure

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Any views expressed herein are those of the authors and may not reflect the official views and policies of the U.S. Minerals Management Service.

[1] See footnotes at end of text

required for the exploration, development, and production anticipated from the proposal in question. Each scenario is based on an analysis of existing geologic data and assumptions about the extent to which unleased resources will be discovered and produced at specified price paths. For some analyses, the scenario includes a forecast of the annual distribution of these activities over time, e.g., the number of exploration wells in year 1, the number of exploration wells and of development wells in year 2, etc. For the GOM, these estimates are provided for several water depths, from shallow to ultra deep water.

The E&D scenario for a proposed 5-year program encompasses all anticipated projects in each OCS planning area. For a single proposed lease sale, it encompasses all anticipated projects in the OCS planning area for which the sale is scheduled. Post-lease analyses would tend to focus on a specific project, for which the direct effects may be known.

For the GOM planning areas,[2] the E&D scenario provides estimates of

- number of new exploration & delineation wells
- number of new platforms
- number of new development wells
- miles of new pipeline installed
- number of workovers
- quantity of oil produced
- quantity of gas produced
- number of new gas processing facilities
- number of platforms removed.

Any model that MMS uses to estimate regional economic impacts of proposed OCS oil and gas activities must do several things. First, for each OCS activity related to a specific OCS planning area, the model must estimate the typical industry expenditure, then allocate that expenditure among the onshore geographic areas to be considered in the analysis. Such models must be developed specifically for OCS oil and gas analyses to reflect the unique expenditure patterns of OCS-related companies. For example, OCS activities require much larger purchases of steel pipe and air and water transportation than do onshore activities, where a higher proportion of expenditures necessarily goes to the other factors, including ground transportation. Industry expenditures also vary by the water depth at the location of the exploration or production facilities. For example, an exploratory well in 50 meters of water is expected to be drilled using a jack-up rig and to cost about $4 million, whereas an exploratory well in 950 meters of water may be drilled using a drill ship and cost more than $10 million to complete.

The model also must estimate indirect and induced effects. For an EIS, MMS needs impact data for specific onshore areas composed of single boroughs/municipalities (in Alaska) or groups of contiguous counties/parishes that exhibit shared economic activity (in GOM States). Because the secondary and tertiary spending patterns resulting from direct expenditures vary by onshore area, a separate set of multipliers[3] must be used for each.

In addition, an accurate model must reflect typical commuting patterns for workers in OCS-related industries. For example, OCS platform workers tend to spend a week or more offshore, followed by the same period at home. This allows them to commute longer distances and results in such workers spending most of their income outside the areas of analysis. Therefore, to accurately model the onshore effects of OCS activities, an analyst must know what percentage of workers spend what portion of their income where, then must use a customized model or must "recalibrate" a more general model to properly characterize local labor payments in certain industries.

Regional Economic Modeling: Previous MMS Methodology

Prior to the Autumn of 2000, the Alaska OCS Regional Office and the GOM OCS Regional Office used independently developed processes to estimate regional employment impacts for EISs. The equitable sharing analysis was done with existing data, with little use of output from impact models.

In the Alaska office, MMS used the "Manpower" model to convert E&D scenarios into estimates of direct employment expected to result from a proposed OCS lease sale. Manpower, which was developed by MMS employees with contractor assistance, consists of a set of simple multipliers on spreadsheet pages in a Corel Quattro Pro notebook. MMS used the Rural Alaska Model (RAM), developed by the University of Alaska, and the output from Manpower to estimate indirect and induced employment. The RAM consists of a set of worksheets in a Microsoft Excel workbook. Like Manpower, it uses simple multipliers to estimate results. The RAM is actually a collection of 10 models, 1 for each of 10 local onshore areas.

In the GOM office, MMS used an unnamed, staff-developed, MS Excel spreadsheet to estimate direct, indirect, and induced employment effects. The GOM office based its direct employment and population projections on average employment requirements for OCS activities (by type of activity and water depth), determined through an informal survey of industry employment types and locations. The GOM region allocated onshore direct effects using historical data from an offshore rig locator service. The same model used exogenous multipliers developed and modified over time from County Business Pattern data to estimate indirect and induced employment.

Given the lack of proposed lease sales in either region for more than 15 years, no PC-based models were maintained to estimate regional employment impacts for the Atlantic OCS region or the Pacific OCS region. The Pacific OCS Regional Office had planned to use analyses of internal environmental studies to help estimate direct employment effects and to use proprietary IMPLAN data and software to estimate indirect and induced employment effects.

The New MMS Consistent Approach to Regional Economic Impact Modeling

In the mid-1990s, MMS formed the Developmental Benefits Model Assessment Team (DBMAT) to develop proposals to improve its regional economic impact models. The DBMAT was composed of members from each MMS OCS regional office and relevant units at MMS headquarters.

While the DBMAT researched a broad range of models used for regional economic impact analyses, it is important to note that there was, and is still, no secondary source from which MMS could obtain data showing how a given expen-

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Regional Economic Impact Modeling *(continued from page 19)*

diture on OCS oil and gas activities reverberates through onshore economies. No standard statistical series, such as those compiled by the Departments of Commerce and Labor, gathers data on the offshore oil and gas industry. In every case, offshore is combined with onshore oil and gas or with all mining. These distinctions are important because of the different spending patterns cited above and because the sector in which money is spent and workers are employed can strongly influence the level of indirect and induced effects.

The DBMAT proposed a two-step modeling process that would allow the development of region-specific models to be developed under a consistent methodology, whether for large, Statewide or multi-State areas in equitable sharing analyses or for sub-State areas in specific pre-sale analyses. Given the Team's belief that there was no single readily available model adequate for all MMS analyses, this proposal called for region-specific "first-step" model components to estimate direct effects and "second-step" model components comprised of, or including multipliers from, a single static input-output model[4] with region-specific databases to estimate indirect and induced effects. Accordingly, the first-step component would include a cost function[5] that not only estimated the total required expenditures for each E&D expenditure but also allocated expenditures among industrial sectors in each onshore area.

After the proposal was approved, the DBMAT selected the IMPLAN (IMpact Analysis for PLANning) model for the universal second-step component, because it had the simplicity and flexibility to meet current and unforeseen MMS needs, and it was the most widely used input-output model available with regularly updated data for all coastal areas. Furthermore, IMPLAN had been used to analyze impacts from oil, gas, and non-oil related economic shocks in all MMS regions.

The necessary first-step data for the two OCS regions available for leasing consideration was obtained through outside contracts. The Center for Energy Studies (CES) at Louisiana State University developed the data for the cost functions and onshore allocations for the GOM under a Coastal Marine Institute contract. Jack Faucett Associates (JFA) was hired to develop first-step models for the Arctic and Sub-Arctic Alaska OCS.

CES and JFA had to determine the appropriate technology for each phase of development, e.g., exploratory drilling or production operations and maintenance, then identify necessary expenditures and the industrial sectors and geographic locations of all supporting activities. For example, while a jackup rig is most likely to be used in 0-60 meters of water in the Gulf of Mexico, other drilling structures would be used in deeper water. However, JFA found that in the Beaufort Sea, where production from Federal waters will not begin until late this year at the earliest, normal rigs could not withstand the winter conditions, and production would most likely take place from artificial gravel islands until oil and gas activities eventually move out of shallow water. The cost functions for these water depths and different kinds of drilling structures can vary considerably, as can the locations of the companies providing the necessary goods and services for fabrication and installation. About 36 percent of platform fabrication and installation expenditures for a project in 0-60 meters of water go to IMPLAN sector 258 (Steel Pipe and Tubes), while that rises to 56 percent or more for a project in more than 900 meters of water. Nearby companies are likely to meet most needs for shallow-water projects in the GOM, while some important capital goods (like hulls for deep-water platforms) for deep-water projects–and the majority of goods and services for Arctic Alaska–may come from outside the region. All MMS models treat expenditures on foreign goods as leakage, while models designed for EIS's also exclude expenditures anywhere outside the local areas of interest.

These are among the many factors influencing the data used in building a first-step model. For more in-depth explanations, see the papers by Dismukes & Olatubi and Skolnik & Holleyman in the proceedings for the April 2001 International Conference in Houston. The full CES and JFA reports to MMS should be available in mid-2001.

Microsoft Access was selected as the software to link the E&D scenarios, the first-step components, and IMPLAN.[6] Given the large number of inputs for the second-step component, usually numbering many thousands, IMPLAN Pro software and data are used only to provide and regularly update sets of multipliers for the MS Access model. The IMPLAN software itself also could be used for analyses not requiring extensive data entry.

Because the magnitude of indirect and induced effects for each industry varies by geographical location, MMS develops a separate MS Access model for each onshore area in an analysis. For the Gulf of Mexico, these onshore areas are

- TX-1 (Aransas, Calhoun, Cameron, Jackson, Kenedy, Kleberg, Nueces, San Patricio, Refugio, Victoria, Willacy)
- TX-2 (Brazioria, Chambers, Fort Bend, Galveston, Hardin, Harris, Jefferson, Liberty, Matagorda, Montgomery, Orange, Waller, Wharton)
- LA-1 (Cameron, Calcasieu, Iberia, Lafayette, Vermilion)
- LA-2 (Ascension, East Baton Rouge, Lafourche, Livingston, St. Charles, St. James, St. Martin, St. Mary, St. John the Baptist, Tangipahoa, Terrebonne, West Baton Rouge)
- A-3 (Jefferson, Orleans, Plaquemines, St. Bernard, St. Tammany)
- MA-1 (Baldwin, AL; Mobile, AL; Hancock, MS; Harrison, MS; Jackson, MS; Stone, MS)
- FL-Panhandle (Escambia, Santa Rosa, Okaloosa, Walton, Bay, Franklin, Gulf)
- FL-Rest of the western coast[7]
- Rest of the U.S.

The model also produces direct spending estimates for Rest of the World, but these results are not used in either the equitable sharing analysis or the EISs.

For Gulf of Mexico analyses, the entire two-step process is accomplished within the MS Access model, as shown in Figure 1.

Figure 1 shows the design view of a sample MS Access query for the area called LA-1 that illustrates how the GOM models work. The first box in the upper left corner of the figure represents the Exploration and Development scenario, required for any model to produce data. The second requirement is the first-step component–the third box from the left, which contains the cost functions by phase (e.g., exploratory drilling) and water depth. The MS Access query uses this data table (see footnote 5) to estimate the expenditures resulting from the activities and to allocate those expenditures to industrial sectors in the relevant onshore area addressed by this model. So for each exploratory well in 0-60 meters of water, for example, about 70 percent of the estimated $4.25 million spent to drill each well will be allocated to sector 38 in the group of parishes called LA-1.

The other boxes to the right comprise the second step of the model. These are the multipliers for employment, employee wages, personal income, total value added, and total economic output. They estimate, for example, the number of industry jobs created in LA-1 as a result of each million dollars spent, as well as the number of jobs created by secondary industries and by households with industry employees. The equations performed on the data are in the bottom section of the window.

The models for the Arctic and the Sub-Arctic OCS are similar in concept, but the linkages between the first-step and second-step components are more complex. The two major differences between the Alaska models and the GOM models are that the direct expenditures for the former are estimated and allocated by the stand-alone Arctic and Sub-Arctic Impact Models for Petroleum in Alaska (IMPAK), developed in MS Excel by JFA, and that Personal Consumption Expenditures (PCE) are independently estimated.[8] The MS Access model uses direct expenditures on capital, materials, and purchased services from IMPAK to stimulate the indirect IMPLAN multipliers and uses payments to labor (PCE) to stimulate the induced IMPLAN multipliers. The Arctic IMPAK estimates the direct expenditure and employment effects of proposed activities in the Beaufort Sea on the North Slope Borough, while the Sub-Arctic IMPAK estimates the direct effects of proposed activities in Cook Inlet on Anchorage, on the Kenai Peninsula Borough, and on the Kodiak Island Borough. Both models estimate direct expenditures in the Rest of Alaska and in the Rest of the U.S.

At present, the estimated effects of proposed activities in other Alaska OCS planning areas, such as the Chukchi Sea and the Gulf of Alaska, are estimated using the existing models and certain rules of thumb for adapting the results.

For the 5-year program's equitable sharing analysis, the models will allocate impacts to the onshore "regions" used in equitable sharing analyses previously upheld by the court. These are much larger geographical areas than those for

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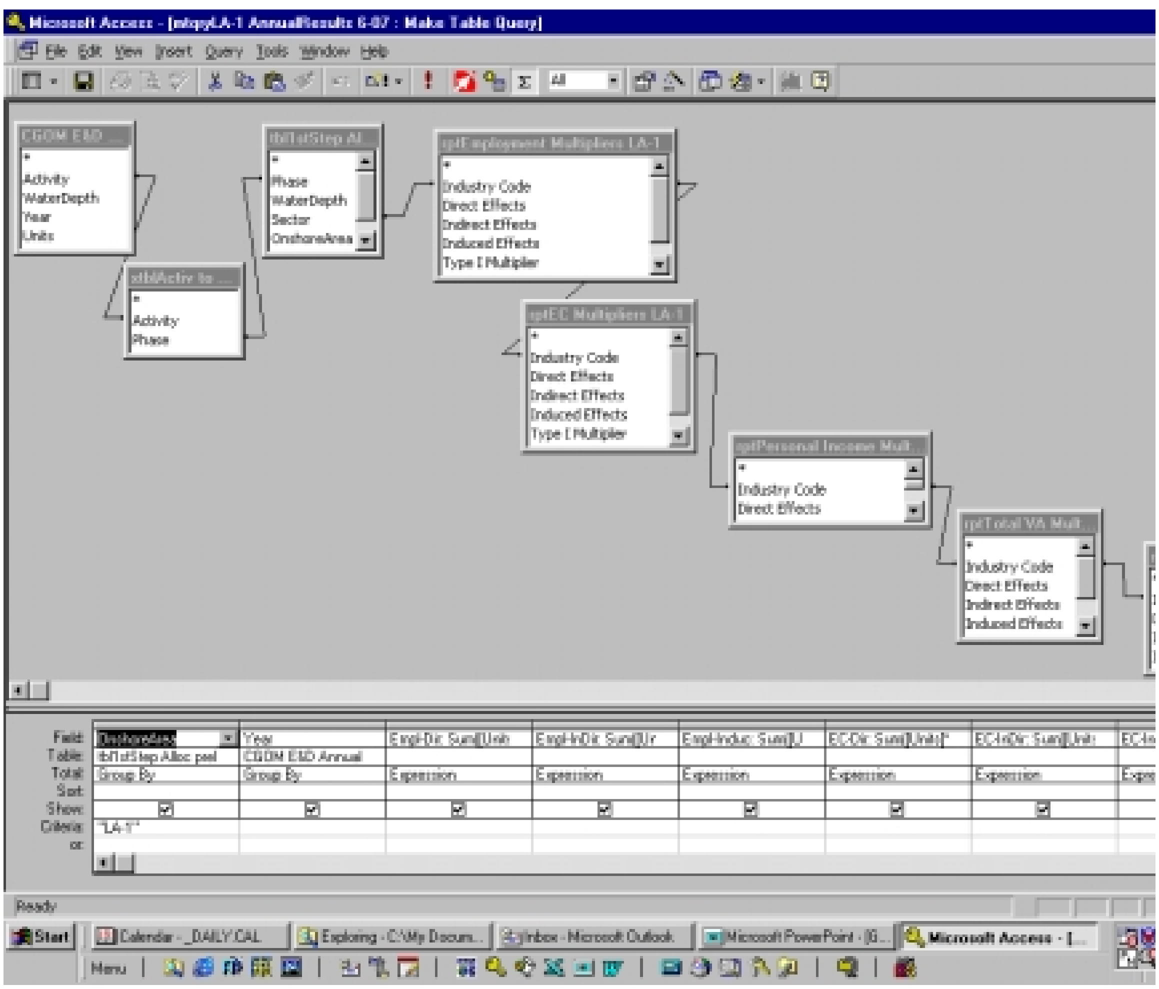
Figure 1
Sample View of Microsoft Access Model for Gulf of Mexico



Regional Economic Impact Modeling *(continued from page 21)*

EISs. These regions are:

- Region I—Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia
- Region II—North Carolina, South Carolina, Georgia
- Region III—Florida
- Region IV—Texas, Louisiana, Mississippi, Alabama
- Region V—California
- Region VI—Washington, Oregon
- Region VII—Alaska.

The requirement for an equitable sharing analysis applies only to a new 5-year program, while the NEPA analysis (EIS) must be done for both the 5-year program and the pre-sale decision processes.

Looking Forward

The new consistent approach to regional economic impact modeling will be thoroughly tested over the next year or two, as MMS conducts at least two iterations of the equitable sharing analysis and the EIS for the 5-Year Oil and Gas Program for 2002-2007–which must be in place by mid-2002. A multi-sale EIS analysis also will be completed for proposed sales in the Western and Central GOM planning areas. During this period, MMS will be looking for ways to improve upon the initial models that have been developed under this approach.

Some of these improvements will come from better data. For example, MMS is confident that its allocation of expenditures to specific onshore areas is fairly accurate overall; however, it may be appropriate to further refine the allocations according to planning area and water depth of the oil and gas resources in question, as well as by sector. We expect to find that the owner of a shallow-water oil and gas lease can choose from a number of manufacturing and service facilities in nearby GOM areas but that the choice for deep-water projects may be limited to a very few facilities. This may be especially true for drilling equipment and platforms. A case in point is the Shell Mars Tension Leg Platform. Its 15,650-ton hull was fabricated in Italy; its 7,200-ton deck was fabricated in Morgan City, Louisiana; and its 12 piles and 12 tendons (weighing a total of almost 10,000 tons) were fabricated in Ingleside, Texas.

In other cases, these improvements may come from refinement of existing data, for example, developing cost functions for specific technology (e.g., jack-up rigs). For analyses of identified projects, these would be better than the weighted averages for mixed technology that are used for more general proposals, like lease sales. Given that the existing models use a static input-output model to approximate a dynamic process, MMS intends to develop a methodology to spread certain E&D expenditures across years, where appropriate (e.g., for fabricating and installing platforms in deep water).

Other changes will result from the incorporation of additional research results on commuting (and spending) patterns for offshore workers, wage rates in related industries, State and local government revenue collection and expenditure patterns, and offshore contractor expenditure patterns that may be masked in existing data.

Finally, MMS hopes to take advantage of more sophisticated features of MS Access and Visual Basic software, as well as improvements to IMPLAN Professional software and data. Future versions of IMPLAN Pro may allow MMS to create multi-regional models, which would capture more of the inter-regional trade interactions. MMS also can develop uniform input formats and Visual Basic programming instructions within MS Access to make models easier to update and easier to link to new E&D scenarios, as well as to make them more user-friendly.

Footnotes

[1] For the purposes of this paper, an oil and gas project includes all activities necessary for a company to discover and produce oil and/or natural gas resources from a single field, beginning with exploratory drilling and ending with removal of the drilling structure.

[2] The activities in an E&D scenario for the Alaska OCS are equivalent but, especially in the Arctic, not identical. For more detail, see the paper by Skolnik & Holleyman, in the proceedings of the 24th International IAEE Conference.

[3] Multipliers estimate the extent to which initial spending reverberates through the economy. For example, an indirect multiplier of 1 would indicate that for every initial dollar spent on oil and gas activities, another dollar is spent by businesses in the local economy.

[4] A static model approximates an outcome for which all changes occur at once, as opposed to a dynamic model, which allows for changes and variable interactions over time and is thus much more complex. An input-output model estimates the monetary interactions among all industries required to achieve a specified change in output in one or more sectors.

[5] The MMS calls the spending estimation and allocation to industry sectors a "cost function" to avoid confusion with the similar "production function" for each sector in the second-step model. Because the analysis of direct effects also requires allocation of expenditures to the appropriate onshore geographic areas, this is also sometimes inferred by the term "cost function."

[6] MS Access stores data in tables (data sets) that can be manipulated by queries (sets of programming instructions). For example, the E&D table contains the activity level estimates for a specific E&D scenario. Another table can contain the estimated amount spent in each industrial sector for each kind of activity. An MS Access query can be designed to multiply the values in the E&D table by the corresponding values in the other table to produce an estimate of the total amount spent in each sector as a result of all the projected oil- and gas-related activities in the E&D scenario.

[7] Specification of the Florida areas sometimes varies, expanding to as many as four areas.

[8] Due to the extent that sector production functions in Alaska differ from the national averages used in IMPLAN, direct expenditures from either IMPAK are allocated well beyond the first round of spending. The goal of both JFA and CES was to allocate expenditures down to the sector level at which the IMPLAN production functions would be as accurate as their OCS cost functions. For Alaska, this often required JFA to effectively create new industries.

Factors Relevant to Incorporating Wind Power Plants into the Generating Mix in Restructured Electricity Markets

*By Michael R. Milligan**

Introduction

In many places throughout the world there is increasing interest in developing power plants that are fueled by the wind. Wind power plants are a clean source of electricity. However, many electric generating companies are reluctant to install significant wind capacity because of the intermittent nature of the resource. Wind power plants cannot be controlled in the same way as their conventional cousins, and are subject to the availability of the wind itself. From one year to the next, it is also likely that the yield from a wind power plant will vary. Both of these issues can be characterized as different aspects of risk, which is becoming an important topic as the electricity industry moves toward a greater degree of competition under restructuring.

To reduce the risk of depending too heavily on one specific type of generation or fuel, resource-planning techniques have incorporated methods of portfolio diversification theory. Financial option theory is also used to evaluate the relative costs of building a power plant now or building it later. Another strategy is hedging, which can consist of forward trading or contracts for differences. Applying these theories and practices to resource planning helps companies assess and reduce risks in the emerging competitive environment.

In the regulatory environment, risk is shared by the consumers and the power company, although some would argue that most risk is borne by the consumer while the monopoly power company enjoys a virtually guaranteed rate of return set by the regulator. But as electricity markets become more open, power companies are attempting to recognize and quantify various risks that they had previously been able to ignore. Some of these include the risk that a new unit won't be completed when it is needed, the risk of fuel cost escalation, or future regulations covering various emission levels. Intermittent power plants, such as wind plants, enter risk discussions in several ways. There is the obvious risk that the wind power plant may not produce power when it is needed, but that is balanced against the risk undertaken by building power plants for which lifetime-fuel costs cannot be accurately determined at the time of plant construction. Although the fuel for a wind plant is inexpensive and in plentiful supply, the timing of its availability is not always known in advance, and is subject to variation. Other risks faced by power producers include the risk of future emissions abatement requirements and the resulting effect of the cost of conventional power generation. Power companies facing restructuring are familiarizing themselves with the principles needed to analyze the risks and benefits associated with wind power plants. As we move forward, risk-based performance measures of power systems, markets, and generators will become more prevalent.

This paper examines some of the factors related to the operation of, and planning for, wind power plants. In spite of the move towards restructuring and new ways of doing business, utilities that are evaluating wind power plants are asking questions about the intermittency of wind and the implications of this intermittency on power system operation. To deal effectively with intermittency, accurate wind forecasts can prove helpful, both in regulated and in unregulated markets. Another important consideration involves the measurement of available capacity to determine whether electric capacity is sufficient to cover demand. This leads us into the area of reliability assessment, and to reliability-based measures of capacity credit.

The power generation industry is assumed to include many types of firms, ranging from small firms that own one or two generating resources, to behemoth firms with generation ownership up to 30,000 megawatts (MW) or more. In this paper the term "utility" means power generator (also known as generating company or GENCO), as we straddle environments that are still regulated and those that have restructured. It is also assumed that at least some of these companies will hold both wind-generating capability and other conventional power generators, and that restructuring is a work in progress. The electricity industry has not been down this road before, and predictions about how a specific market will perform can only be answered with experience. As one of the earliest examples of restructuring, the United Kingdom power system has recently made some very significant changes in many aspects of the operating procedure of the electricity supply industry. Current events in the California electricity market demonstrate that generating supply adequacy, reliability, and capacity measurements, are still very important. Further discussion in this paper concerning the electricity market is made under the assumption that the restructuring dust worldwide has not yet settled. There are many underlying technical issues that must be addressed by the market, and the first and even subsequent versions of the market rules may not address all of these issues.

The results presented in this paper are from various projects undertaken at the U.S. National Renewable Energy Laboratory (NREL), involving electricity production simulations using actual wind-speed data, generator data, and electric load data. Data were also used from several different utilities or regions and many wind sites. The hourly data used for wind power are based on actual wind data and are applied to various wind-turbine power curves, all of which represent actual wind turbines, to calculate the hourly power output of several hypothetical wind power plants. The electricity production simulation and reliability programs used for this work are Elfin (a load duration curve model produced by Environmental Defense) and P+ (an hourly chronological model produced by the P Plus Corporation). In the wake of restructuring, both of these models have been enhanced to allow for the new electricity markets, but the primary least-cost dispatch algorithms are still at the heart of the models. Results from an experimental chronological reliability model developed at NREL are also included in this work. Although some of the focus and emphasis changes, competitive pres-

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sure will induce firms to assess the best (least expensive) way to produce electricity, subject to profit maximization. To maintain the reliability of the electricity supply, either some form of reliability-based pricing or regulation may become necessary.

Some of the factors relevant to incorporating wind plants into the generation mix can be framed by these questions: Does a wind power plant offer any value to a generation company that owns a variety of generating resources? Can wind energy systems reduce the need for conventional generation in the industry supply portfolio? If so, how much generation can be displaced, and how can it be measured? Does the intermittency of wind power plants present any significant problems for the operation of electric power systems? Can any of these problems, or problems of lesser significance, be mitigated, and if so, how? Will it be possible for wind plant owners/operators to participate in the newly emerging electricity markets, such as day-ahead markets, in the new market structure?

The Value of Wind Power Plants

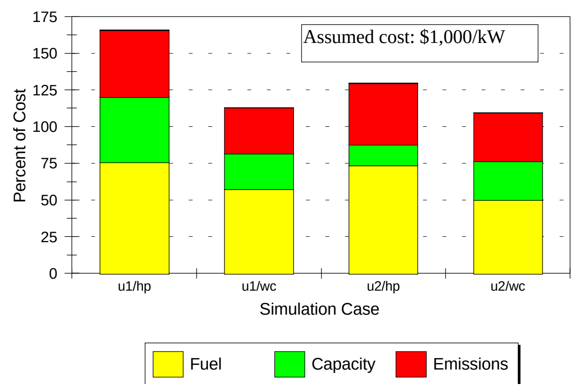
It is widely recognized that wind power plants can provide energy value to the grid. This value is a result of the reduction in electricity generated from conventional power plants, made possible by the wind plant. The value of offset fuel consumption and emissions reduction can be calculated by an electricity production simulation model. In many cases wind power plants can offset the need for conventional power plants. The variable and marginal costs of wind generation are typically less than most, if not all, other power plants because there is no fuel cost, and operation and maintenance costs are very low. In regulated electricity markets, this means that each wind-generated kilowatt-hour (kWh) would be utilized whenever available, making it possible for the utility to ramp back on other load-following power plants. As we move toward a restructured industry, generating companies with diverse generating portfolios will still attempt to produce electricity, subject to various bidding strategies, at lowest possible cost and highest possible profit. Therefore, a generating company that owns a portfolio of generators that includes wind power plants will attempt to maximize the efficient use of the wind plants to reduce fuel costs associated with conventional power generation.

The value that wind plants contribute to generating companies depends heavily on the GENCO's specific combination of generators, and the influences of the chronological wind pattern and its relationship to the expected load. A wind site that is attractive to one utility may not be as attractive to another. Milligan and Miller experimented with various combinations of wind sites and utility data and found significant variations in the benefit of otherwise identical wind power plants to different utilities. In a study by Milligan, two large utilities were modeled. The model paired each utility with each wind site, one at a time. The benefit provided by the wind power plant includes three parts: (1) energy, which represents the reduction in conventional fuel cost resulting from adding a wind power plant; (2) capacity, defined in this case by the shortage method adopted by the California Energy Commission (CEC) prior to restructuring in California; and (3) emissions value, which was also valued on a per/ton basis by the CEC prior to restructuring. The full social value of reduced emission levels may not find its way into the market, but is a well-known market externality. The energy, capacity, and emission values were calculated by initially running the model without any wind generation. After the results for this no-wind case were collected, the values were recalculated to include a 125 MW wind power plant. The difference between these two cases gives us the value provided by the wind power plant.

Figure 1 illustrates the results for the two utilities, U1 and U2 (the utilities are not identified because of prior agreement). The wind sites utilized in this study include a site from a West Coast mountain pass (WC) and a site from the High Plains (HP). The vertical axis of the graph represents the benefit as a percent of cost, which is $1,000/kW. It is clear from the diagram that (a) a given wind site will contribute a different level of value, depending on the utility, and (b) the value of wind power to a utility will vary as a function of the chronological variation of the wind power plant.

Figure 1

Value vs. Cost for Several Wind Site and Utility Combinations



Milligan also shows the results of several electricity production simulations using a chronological model. Using various combinations of utilities and wind regimes, this work shows the reduction in generation from those units on the margin during periods of significant wind generation when the chronological unit-commitment and economic dispatch is optimized to include the wind plant. For one of the large utilities that was studied, the total number of start-stop cycles from conventional power plants was reduced by about 700 cycles/year.

Forecasting, Capacity and Risk

There are several ways to look at the effective capacity of wind power plants. In regulated markets the term "capacity credit" is often used to describe the level of conventional capacity that a wind plant could replace. This section assumes that uses of the term "capacity credit" may be more general in the newly restructured markets. It begins by discussing some general characteristics of various pool bidding processes and the unique issues raised by wind power plants in these arrangements. The discussion will look at short-term markets and the role wind forecasting can play in those markets, followed by an examination of measures of capacity credit that are based on reliability estimates. These estimates have been used in some regulated environments. Whether these will be appropriate in the new electricity markets may still be open to some question.

Bidding Wind Power into the Supply Pool

Because electricity has a higher value during periods of system peak demand, generating companies will have a higher economic incentive to secure a bid into the pool during these times, as compared to periods of relatively low system demand. As the restructuring landscape continues to evolve, differences in many aspects of the wholesale electricity market will surface as they did in California in the United States, and in the United Kingdom. However, an emerging trend is for some mechanism by which buyers and sellers strike agreements on price and quantity during a period prior to the actual transaction. The elapsed time between the agreement and the actual exchange of power may range from hours to days in these short-term markets. This discussion only describes short-term operational transactions, ignoring any longer-term transactions so that we can focus on the operational market.

Wind power plant owners must participate in such bidding arrangements to sell power unless bilateral contracts or market bundling become significant. Although the short-term markets may include some provision to account for spinning reserves to cover unforeseen generator malfunction or higher than anticipated customer load, it is advantageous to the wind plant owner to ensure that the capacity or energy bid into the market can be supplied at the specified time of delivery. However, there are various mechanisms that can be used when contracted power is not delivered as specified. An example of one mechanism is the Balancing and Settlement Code (BSC) in the United Kingdom, in which market participants must pay for any imbalances during a settlement period that occurs after the time of the specified transaction. Therefore the wind plant operator, as do all power plant operators, has an economic incentive to bid quantities into the market that can be reasonably supplied.

For the wind plant operator there is an additional complication. The intermittent nature of the wind makes it impossible to control the power plant the same way a conventional unit is controlled. Significant social costs are imposed during outages, which is why all electrical systems maintain a spinning reserve. However, scheduling more generation than is needed also results in unnecessary costs. The incidence of these costs can vary widely, and can include any combination of the power generators, distribution companies, or ultimate consumers. The total generation supplied should equal total demand (allowing for reserves, ancillary services, etc.) to minimize costs that are induced by either an oversupply or undersupply of electricity. Therefore, the stochastic nature of the fuel source makes it vital for the wind plant operator to obtain an accurate forecast of the wind speed for the power delivery period.

An accurate forecast would have value in bilateral contracting, or any other arrangement under which the wind power plant operator/owner sells power on a scheduled basis. The value of an accurate wind forecast in a pool arrangement will depend on many factors; among them is the generation portfolio that is controlled by the GENCO. If a quick-response unit is part of that portfolio, that unit can be brought online quickly during unexpected lulls in the wind. Conversely, if there is an unexpected period of wind, it is possible that a combustion turbine or other similar unit can be ramped down to avoid the use of a relatively expensive fuel.

Milligan, Miller, and Chapman modeled two large utilities in two regulated markets and showed significant economic benefits of accurate wind forecasts. Their approach was to calculate the optimal unit commitment schedule under various assumptions about wind timing and availability. To introduce forecast error into the model, they modified the wind power availability after fixing the commitment schedule to a specific wind forecast. This allowed them to calculate the difference in power production cost that would result from wind forecasts from various degrees of accuracy ranging from 0% — 100%. They found that the economic benefits of an accurate forecast were substantial because errors in unit commitment and economic dispatch can be reduced or avoided. It is also likely that accurate wind forecasting will help reduce or eliminate any operating penalties that might otherwise occur because of the intermittent nature of the wind resource.

The National Renewable Energy Laboratory is currently working with the Electric Power Research Institute on a wind energy forecasting development and testing program and is conducting independent research on wind forecasting techniques. Accurate wind forecasting may be one of the most important issues facing wind power plant operators in restructured electricity markets. As market-based electricity supply pools continue to develop around the world, wind plant operators must be able to participate in the various bidding arrangements. In the very short-term power markets, it remains to be seen whether separate capacity payments will be made, or whether energy will simply be more highly valued during peak periods than in non-peak periods. However, the penalty for over- or under-scheduling resources during the system peak is higher than during other periods. The most effective tool for the wind plant operator may be an accurate wind forecast for the period that is covered by the bidding process.

Reliability-based Measures of Capacity Credit

As utilities develop more risk-evaluation strategies, a central element will continue to be overall system reliability. This paper ignores the reliability aspects of the transmission and distribution grids, as the number and complexity of transactions on these grids continues to increase. However, this aspect of reliability will be critical in the future. For example, a recent international panel of electric-system reliability experts agreed that: (1) electrical reliability in the United States is very high today, particularly as viewed in the context of generation reliability; (2) the transactions in the wholesale market that will arise from the restructuring of the industry will be far more complex than they were in the past; and (3) system reliability will likely worsen, but will in any case continue to be an important issue in a restructured market. This section will focus on the reliability of the generating system. Recent experiences in parts of the United States indicate that concerns over the adequacy of the generation supply appear to be warranted. Given the stochas-

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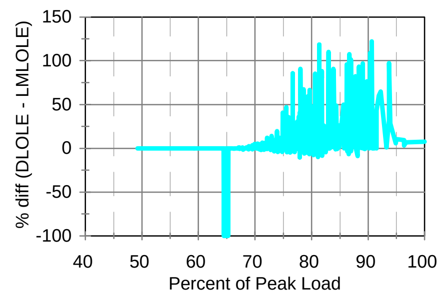
tic component of electricity demand and a corresponding stochastic component of the generation supply, the grid operator is still faced with the problem of balancing loads and resources. As regional coordinating councils or power pools evaluate the electricity supply in future peak periods, risk assessment will continue to be important. Large GENCOs still perform reliability studies, and measures such as loss of load probability (LOLP) are still used to assess system adequacy. Until the new BSC recently went into effect in the United Kingdom, LOLP was used to determine capacity prices, although that caused significant volatility in those prices.

There are several ways in which one can evaluate the reliability contribution of a single power plant to the generating system. One way involves calculating the reliability measure of choice (LOLP or expected energy not served, [ENS], for example) and comparing the results with and without the generator of interest. Another approach is closely related, but instead of using LOLP or ENS, the reliability measure is converted to a megawatt quantity by increasing the peak load until the reliability matches the base case (excluding the generator of interest). This quantity, called the effective load carrying capability (ELCC), is well known and has been widely used for many years. ELCC has traditionally been called a measure of capacity credit. To evaluate competing power plant options, one can calculate the ELCC of each plant to determine the effective capacity contributed by each one. Another related approach is to compare an intermittent power plant, such as wind, to its closest competitor; often a gas plant. The evaluation strategy works like this. For a given size gas plant, calculate the system reliability for the generating system, including the gas plant. Record the system reliability attained by the calculations. Then remove the gas plant, substituting increasing penetrations of wind capacity until the reliability measure equals the system reliability in the gas plant case. Once this equality has been achieved, the rated capacity in MW of the wind plant is reliability-equivalent to the gas plant.

ELCC can be calculated for a wind power plant, using the same basic technique as for conventional power generators. The advantage to using a measure such as ELCC is because it takes the relative load level and timing of wind power delivery into account. For example, a wind power plant that generates most of its output during off-peak periods would achieve a lower ELCC value than a wind plant that generates most of its energy during peak periods. ELCC also makes it possible to compare two or more generation options that deliver the same level of reliability to the grid. Although these calculations can be done with a load-duration model, the results are more accurate with actual hourly chronological wind power output and hourly chronological load data.

However, many chronological production simulation and reliability models may not accurately capture the probability that a wind plant may not deliver its statistically expected output and also model the time-variability of a wind plant. Figure 2 shows a comparison of the conventional reliability calculation of loss of lead expectation (LOLE) as calculated by a commercial model, and calculated by an experimental chronological reliability model developed at NREL. The graph shows the difference as a function of the load level for the electrical supply in Minnesota, along with a large composite wind site. The graph shows that there is a significant difference between what is normally calculated

Figure 2
Comparison of Reliability Measures of a Wind Power Plant



when wind power is treated as a load-modifier (LMLOLE) in the modeling process, as compared to a direct assessment based on the chronology of the wind power output (DLOLE). As the need for wind power plant reliability assessment increases, it will be important to adjust the fundamental reliability algorithm so that more accuracy can be achieved.

Will ELCC still be relevant in the new markets? There will continue to be a need to measure capacity contributions and risk. If ELCC is not the right measure, another may take its place for large-scale evaluations of generation adequacy (pools, control areas, etc.) Investors and GENCOs also need information that helps compare different power generation options, risks, and estimated rates-of-return for alternative power plants. These rates-of-return may be based, at least in part, on capacity payments, depending on the structure of contracting in the electricity market. ELCC provides important information about how the plant operates in the context of the market or GENCO assets and has a built-in risk component, so it may continue to be useful as risk analysis becomes more important in the new markets. ELCC or variations on ELCC could also play a role in determining capacity payments or risk-based assessments of whether a wind plant operator is likely to meet a bid into a day-ahead or hours-ahead market. Because of the evolutionary nature of restructuring, the notion of capacity credit may be somewhat transitional in nature, and whether ELCC continues its useful life in the long term may be open to some question.

Year-To-Year Variability and Extensions to Generalized Risk Assessment

Because wind speed can vary significantly from year to year and from hour to hour, capacity credit estimates that are based on a single year (or less) of data and modeled without taking this variation into account may not be credible. This section examines modeling techniques that can help assess this variation, and suggests that these methods can be extended for generalized risk assessment.

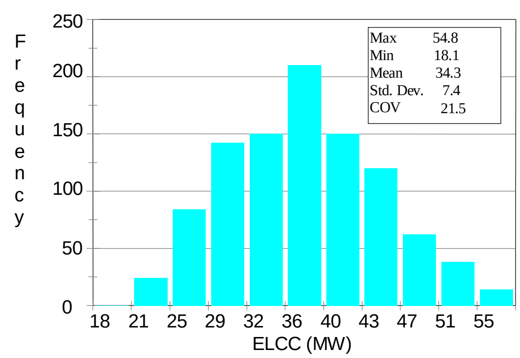
Many production-cost and reliability models have a Monte Carlo option that allows sampling from the probability distributions of generator availability. This approach is used to obtain a better estimate of the range of possible outcomes than can be provided by the usual convolution approach.

Another advantage of the Monte Carlo method is that it provides estimates of various probability distributions, such as system reliability and system costs. The P+ model also has a branching option that combines the more efficient convolution approach with the more precise Monte Carlo method. The branching technique performs the usual convolution on all but one generator. This generator's state will be sampled repeatedly via Monte Carlo, holding all other generator values to the expected values from the convolution. This allows the analyst to focus on the effects of a particular generator, without paying the full price of heavy execution time that can be exacted by full Monte Carlo simulations. An excellent discussion of this technique in the context of chronological production cost models can be found in Marnay and Strauss.

This approach appears to be ideal for modeling wind power plants. Unfortunately, the Monte Carlo simulation procedures generally sample from a very simple probability distribution that is not appropriate for wind power plants. This leads us to consider separating the probabilistic sampling from the production-cost model. The method involves repeated creation of synthetic wind-speed data, that can easily be used to calculate hourly wind power output. One can obtain a sequence of such data sets, and then run a series of production model simulations, capturing the results of these runs and summarizing in a convenient form. The Monte Carlo process is used to create the synthetic wind series, and the production-cost or reliability model can be applied to each. This is sometimes called "Sequential Monte Carlo" to differentiate it from the Monte Carlo logic that is often found in the models themselves. Milligan illustrates such a Monte Carlo method, and it is similar to a technique proposed by Billinton and Chen. Milligan applies this approach to a 13-year data set, and compares the capacity credit results obtained with the external Monte Carlo method with results using the actual wind-speed data. The findings indicate that this modeling procedure did a very good job of estimating the variability in capacity credit, but somewhat underestimated the variation in energy production. Milligan and Graham extend the basic framework, using the Elfin and P+ models, and introduce a reduction technique to help minimize the significant model run-time that is required for the full simulation set.

The Milligan and Graham study examined the influence of inter-annual variations in wind on ELCC, production cost, and the scheduling of various conventional generators. Their

Figure 3
Estimated Variations in Effective Load Carrying Capability of Wind Power Plant



approach was to generate 1000 synthetic hourly time-series of wind speed with properties similar to actual hourly wind speed. For each of the synthetic series, they ran a production simulation model and calculated ELCC. Although this approach is very time-consuming, it helps answer basic questions about the likelihood of significant variations in the timing and availability of wind power. Figure 3 shows a frequency distribution of 1000 model runs based on a wind plant with a rated capacity of 100 MW. From the graph we can determine that 500 times out of 1000 we would expect the ELCC of this particular wind plant to fall between 32% and 40% of rated capacity.

The same technique can be applied to various other items of interest. For example, a GENCO can run such a model to determine the likelihood of committing a conventional unit given a particular bidding strategy and expected wind forecast error. Milligan and Graham successfully applied this method to examine various generating schedules and costs that would vary as a function of year-to-year changes in wind generation. One of the by-products of this type of modeling is the probability distribution of the parameter of interest.

Impacts of Geographic Dispersion

Several studies have examined the issue of geographically dispersed wind sites and the potential smoothing benefit on aggregate wind power output. The principle behind this benefit is that lulls in the wind tend to be more pronounced locally than over a wide geographic area. Building wind capacity at different locations may help reduce the problems caused by the intermittency of the wind resource, although the benefit of this geographic spread may be limited by various control area constraints. Wind developers in competitive electricity markets will likely examine these effects closely and use broader geographic areas to reduce the risks of not meeting committed capacity targets and highly varying wind output. Kahn's analysis is based on data collected in California. Grubb analyzes the effects of smoothing from wind generating units in Britain. Milligan and Artig examined a reliability optimization for the state of Minnesota but did not address economic benefits. Ernst provides an analysis of short-term, high-resolution wind data in Germany. And Milligan and Factor examined a geographical optimization using two optimization targets: reliability and economic benefit. All of these studies find that the geographic spread of wind generators provides a smoothing benefit when wind output is aggregated. Although it is measured differently in these studies, the results appear to be robust across time-scales ranging from minutes to hours.

From here, the analysis can get a bit complicated. The benefits of geographically dispersed utility-scale wind power plants can be analyzed to maximize a number of optimization targets. A joint project undertaken by NREL and the Minnesota Department of Public Service set out with a goal to find the combination and sizes of wind power plants that would maximize system reliability. Eight hundred twenty-five MW of rated wind capacity was selected as the total level of installed capacity, corresponding to the capacity level that was negotiated between the state of Minnesota and Northern States Power as part of the Prairie Island nuclear waste storage agreement. Milligan and Artig applied a fuzzy logic

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search technique to examine the most promising locations and sizes, evaluating the composite generating system reliability as a function of the geographic dispersion of wind capacity for the state of Minnesota. They found that the highest level of generating system reliability was possible by installing the wind capacity at a combination of sites, and that hourly variation in wind power output can be substantially reduced when a combination of sites is used.

Milligan and Factor did a similar analysis for the state of Iowa, confirming the results from the Minnesota study. They applied both a dynamic fuzzy search technique and a genetic algorithm to the optimization process. However, in this case, there were twelve wind sites with a total installed capacity target of 1600 MW. Their model was run with projected hourly load data for the year 2015, along with detailed information about all power generators and significant power exchanges in the wholesale power market in Iowa. To reduce computer run-time to a manageable level, they considered 50 MW as the smallest increment of wind capacity development that could be built at a single site. Even with this restriction, there are approximately 5 x 10^9 possible ways to build 1600 MW among twelve sites. Given the extremely large number of potential solutions, their technique provides several alternative solution sets, each of which represents either the best or close-to-the-best combination of sites. In this study, they redefined "best" to be that combination of sites that would minimize the cost of running the conventional generating units. Additional model runs identified the combination and location of sites that would maximize electric system reliability, and these are described in their paper.

Figure 4
Top 12 Site Combinations Based on Economic Benefit for Iowa

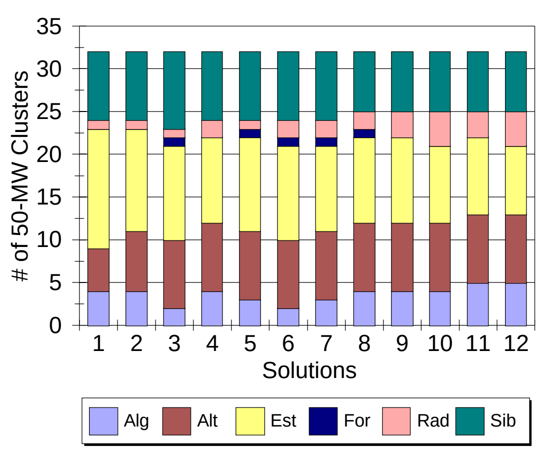

Figure 4 illustrates the basic results. Each bar represents a solution that identifies a particular combination of wind plant locations and sizes. For example, the bar on the far left side shows a recommendation of 4 50-MW clusters at Algona ("Alg"), 5 clusters at Alta ("Alt"), 13 clusters at Estherville ("Est"), and so forth. Bar two shows a slightly different combination of sites than bar one: more wind capacity at Alta is traded against less capacity at Estherville. Even though the number of clusters at Alta and Estherville differ significantly between the two solutions, the economic benefit between these two solutions is extremely small.

Not all sites were chosen for potential development. This suggests that although geographic dispersion can provide benefits, it is not a foregone conclusion that sites not in proximity of each other will necessarily provide economic or reliability benefits to the grid.

Milligan and Factor did significant testing of alternative site combinations that they considered close to the choices recommended by their model. They found a very large number of additional site combinations that were nearly as good (by their metric) as the site combinations that appear in Figure 4. They believe that these multiple solutions provide significant latitude to take other constraints into account that the modeling process does not explicitly recognize. Some of these constraints include transmission constraints, land-use constraints, or other operational issues such as local voltage or volt ampere reactive (VAR) support. This modeling process allows them to investigate the merit of building a small amount of capacity at one of the sites that was not chosen by the optimization process, given that they make small changes in the capacity recommendations at the remaining 11 sites. This provides decision-makers with extraordinary latitude in selecting the locations and sizing of geographically dispersed wind power plants.

Other Issues

On the basis of day-to-day operations, various power pools and control areas have specific ways of assessing the operational capacity credit of all generators in the region. This capacity credit is assessed in part to determine whether available capacity exists in the region during the specified time period. Wind power plants can provide operational capacity credit, although typically at some fraction of rated capacity. As various operating regions and pools mature under restructured electricity markets, the pool accreditation rules may be re-evaluated. It will be important for these rules to treat all resources in an unbiased way and yet recognize the difficulties imposed by intermittent power plants.

In the analysis of Iowa, Milligan and Factor used the capacity credit procedure from the Mid-Continent Area Power Pool (MAPP), one of only two pools that specifically addresses wind power plants. Applying this method to the top 12 fuzzy solutions, the annual average capacity credit was 47% of the rated capacity of the composite wind plant, with significant monthly variation. The MAPP method is based on finding the median output of the power plant during a four-hour window surrounding the monthly system peak, as contrasted with LOLP-based methods that consider a broader time period, weighting the more critical peak hours according to the potential loss of service.

Wind power plants must be located at sites that have a good wind resource. Unfortunately, this may be at a location that is far away from the load center and/or from a transmission interconnection point. There can be an additional complication even if transmission is nearby, but the line is nearly fully loaded during times of peak wind plant output. Because wind power plants typically operate at annual capacity factors in the range of 20% — 40%, the high fixed cost of transmission line construction is spread over fewer kWh than for most conventional power plants. As wind operators bid into an electricity supply pool, transmission capacity must also be available at the time the wind power is available, and this introduces additional complications into the life of the wind plant operator. However, for a wind plant that may reach its peak output for a small number of hours during the year, limited curtailment of wind power output might be preferable to expensive transmission upgrades that are needed for a limited time. The formation and revision of transmission access rules will play an important part in wind plant development in the new millennium. Rules should not impose implicit or explicit barriers to entry, and must fairly allocate costs, even across multiple operating regions. Penalty-based rules in ancillary services markets are less desirable than make-up rules, allowing the generator to replace capacity or standby power that may have been incorrectly supplied. However, penalties that result from operating practices different than instructed by the system operator would be acceptable. The National Wind Coordinating Committee in the United States has analyzed these and other additional transmission issues. The results are available on the internet at http://www.nationalwind.org/pubs.

There are still several unanswered questions regarding additional smoothing effects that were not considered by these hourly analyses. How much smoothing occurs within a wind power plant on a second to second basis? What are the impacts of short-term fluctuations on frequency regulation and spinning reserve requirements? Ernst began to analyze these questions by looking at some high-resolution data from the German 250 MW Wind Turbine Measurement Program. He calculated the smoothing impact of a small number of turbines on regulation, load following, and reserves. He found that a large number of turbines spread over relatively large distances may cause a significant decrease in the relative ancillary service requirements assigned to the wind plant. Ernst also found that there is a clear diversity benefit during short time periods (on the scale of minutes) that arises from the spacing of turbines at the site. Analysis of the regulation impact of the wind power plant can also be influenced by the spatial diversity of the turbines. NREL is currently collecting one-second data from a wind plant in the Midwest, and will conduct a detailed analysis of the power fluctuations and their impact on ancillary services. Another project underway at NREL is to adapt the experimental chronological reliability model so that reliability-based calculations can be used as a basis for allocating the spinning reserve burden to all power plants according to their capacity and frequency of variability.

The smoothing effects from large numbers of wind turbines and from geographically disperse sites appear to be significant. However, it is not yet clear how robust this smoothing effect will be to different sites around the world. As power plant owners and operators examine the question of how to diversify their holdings of different types of power plants to mitigate risk, it seems clear that wind plant site diversification plays an important role in this type of decision analysis. Site diversification reduces risks of sudden drops in wind power and spreads the risk of forecast errors. Smoother wind plant output appears to reduce the burden on regulation and other operational factors.

It is also important to analyze the impact of a wind power plant on spinning reserves and ancillary services in the proper context. For example, in a typical utility control area the level of required spinning reserve is assessed on a system-wide basis, and normally includes consideration of the largest hazard. At relatively low penetration levels, the variability of the wind plant would likely be significantly lower than the largest single generating unit in the control area. Utilities deal with uncontrollable load on a routine basis, and in fact are used to forecasting load based on weather, day of the week, and other factors. Although wind forecasting and power variability may be new issues for grid operators, it appears to be an extension of familiar ideas.

Summary

We understand many of the issues surrounding the use of large-scale wind power plants in regulated markets through a combination of growing experience with wind power plants and the application of various modeling methods and techniques. As the use of wind energy increases, this understanding will expand to a more empirical base and to additional wind sites. Many of these issues will also be addressed as the electricity system moves towards a more competitively based market structure.

From past work we know that wind power plants have capacity, energy, and emissions value, depending on a variety of factors. As the utility industry enters an era of increasing risks, companies will need to be fully aware of the various risks posed by the new markets. The use of large-scale wind power plants presents some risk, i.e., the risk of no wind when it is needed, but alleviates others, i.e. the risk of future fuel cost escalation or the risk of tighter constraints on future emissions levels. Some of these risks can be mitigated by good siting and geographic dispersion. These smoothing effects have been documented in both high-resolution data and hourly data, and can be substantial. It will be useful to apply existing modeling and analysis techniques to additional sites when data becomes available. Other wind-related risks can be mitigated by accurate wind forecasts to help wind plant operators bid into the electricity supply markets.

Transmission will play an important role in future development of wind. As the regulatory and market forces evolve in the newly emerging competitive markets, there are many unresolved issues concerning reasonable and fair cost allocations, incentives for market players to provide sufficient transmission, and consistent rules governing different regions. For competition to succeed, it is critical that transmission access is afforded to all technologies in a way that does not reward those players with substantial market power.

There are several other important issues that must be addressed that will play an important role in determining the success of wind power plants in the new electricity markets. They include the specific regulatory environment of the new markets, power pool rules, and bidding and settlement procedures. Significant levels of market power on the part of large generation owners will also have an important influence on the role of large-scale wind power plants in the restructured market.

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22-22 June 2001, Gas Storage: Stability or Chaos in 2001-2002? at Houston, Texas, USA. Contact: Ziff Energy Group. Phone: 403-234-6555 Email: gasconference@ziffenergy.com URL: www.ziffenergyconferences.com

27-28 June 2001, "Utilities: The Future for the European Market" at Vienna, Austria. Contact: Vaida Kraus, Project Manager, ACBD, UK Email: v.kraus@acbdglobal.com URL: www.acbdglobal.com

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17-21 September 2001, Fifth International Biomass Conference of the Americas, Orlando, Florida, USA at Rosen Centre Hotel. Contact: Organizers: U.S. Department of Energy, U.S. Department of Agriculture, Nat'l Resources Canada & the Nat'l Renewable Energy Lab. Phone: 321-638-1527 Email: joann@fsec.ucf.edu URL: www.nrel.gov/bioam

27-29 September 2001, Hydropower & Dams - Hydro 2001 at Riva del Garda, Italy. Contact: Mr. Gael Bozec, Hydropower & Dams, Aqua-Media International, Ltd., 123 Westmead Road, Sutton, Surrey, SM1 4JH, United Kingdom. Phone: 44-20-8643-4727. Fax: 44-20-8643-8200 Email: conf@hydropower-dams.com URL: www.hydropower-dams.com

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2-3 October 2001, Pacific Northwest Strategies Conference at Portland, Oregon. Contact: Ziff Energy Group. Phone: 403-234-6555 Email: gasconference@ziffenergy.com URL: www.ziffenergyconferences.com

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