THREE ESSAYS ON THE CHANGING U.S. ELECTRICITY INDUSTRY

By

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For my children

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LIST OF ABBREVIATIONS

DOE	United States Department of Energy
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
RTO	Regional Transmission Organization

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In 1996, the Federal Energy Regulatory Commission (FERC) sought to transform the wholesale electricity market with a series of market rules. A product of these rules was the establishment of regional transmission organizations (RTOs) and independent system operators (ISOs) charged with facilitating equal access to the transmission grid for electricity suppliers. The effect of these changes in market structure remains an open question. This dissertation attempts to quantify the impacts of this change in market strucuture in addressing important policy issues facing the electricity sector.

The first essay utilizes a panel data set of the 48 contiguous United States and a treatment effects model in first differences to determine whether there have been changes in delivered electric prices as a result of the establishment of ISOs and RTOs. This estimation shows that electricity prices fall approximately 4.8% in the first 2 years of an ISO's operation and that this result is statistically significant. However, this result is dependent on the presence of states that restructured their electricity markets. When these restructured states are removed from the data set the price effects of RTOs become indistinguishable from zero.

The second essay utilizes the diversity of the United States electricity market and a panel data set of electric utilities for the period 1990-2009 to study the effects that RTOs have had on

the trade of wholesale electricity. It finds that the presence of a transparent wholesale marketplace for electricity has the effect of increasing participation, but that this participation occurs asymmetrically across types of electric utilities.

The third essay utilizes a model that simulates the dispatch of electric generating units in the state of Florida under various prices for CO_2 emissions, and analyzes the challenges that may arise in the determination of optimal emissions abatement policy. It finds that the rate of abatement varies considerably with the price of CO_2 emissions. It demonstrates how the incremental cost curve of emissions abatement may intersect with a CO_2 tax at many levels of abatement, allowing for different characterizations of the 'optimum'.

CHAPTER 1
A BRIEF HISTORY OF THE UNITED STATES ELECTRICITY MARKET

In 1882, the Edison Illuminating Company began to provide electricity to 59 customers in lower Manhattan from its Pearl Street Generating Station, marking it as America's first investor-owned electric utility. Edison Illuminating generated the electricity, transmitted it to customers[1], and distributed it to their homes and businesses. Since it performed all of the functions necessary to supply electricity to customers, it had a vertically integrated structure. The scope and scale of electric utilities grew rapidly from those humble beginnings, but the underlying vertically integrated structure of the industry remained intact for more than 100 years.

In 1996, the Federal Energy Regulatory Commission issued Order 888, paving the way for the restructuring of the electricity industry in the United States. Had this order been issued in a country like Brazil, where the power of the federal government is great relative to the state governments, the sector likely would have been transformed in a uniform manner across the country. However, the country is called the United *States* of America for good reason, as the tenth amendment to the Constitution guarantees that "powers not delegated to the United States by the Constitution, nor prohibited by it to the States, are reserved to the States respectively, or to the people"[2]. As a result of this amendment, it was left to the individual states to determine the extent to which the electricity industry in their respective states was restructured. Through the actions, or inactions, of individual state legislatures, the electricity market in the United States was fractured into three distinct structures. Some states, primarily in the Southeast and the West, maintained the vertically-integrated structure. In other states, primarily in the Midwest, the

[1] As it was direct current, this electricity 'transmission' was only suitable over distances of about a mile, but it was transmission nonetheless. Electricity transmission over longer distances is only feasible after inversion to alternating current.

[2] United States Constitution Amendment X

utilities maintained ownership of all assets, but ceded control of their transmission assets to third parties known as independent system operators or regional transmission operators. A final group of states, primarily in the Northeast but including California, took advantage of the federal order and forced electric utilities to divest either their generation or distribution assets, and opened their markets for electricity supply to retail competition.

Since this restructuring, the electricity industry in the United States has experienced notable events such as the California power crisis of 1999-2001, the blackout of 2003 in the Northeast and Midwest, and price spikes occurring in Texas in 2005 and New York City from 2006 to 2008. While investigations into these events have focused on the behavior of particular parties, principally electricity generators, little has been done to explore the implications of the market strucuture itself. FERC is presently attempting to assess the costs and benefits of RTOs, third party administrators of the electricity transmission system that arose in response to restructuring, through the collection of performance metrics. Once this data is collected, regulators will have better information with which to address their impact, but the metrics are limited to the performance of the wholesale market. As a result, the impact on retail consumers is not addressed by these metrics, nor is the distributional effect of a more transparent market.

New challenges facing the electricity industry center on the the externalities associated with the emission of greenhouse gases during the combustion of fossil fuels. Reaction to differences between the social and private cost of these emissions, even as scientists on both sides of the debate continue to argue over whether such a difference exists, has not been uniform across the globe. Even though the most widespread school of thought is that CO_2 emissions do have an effect on the global climate, and that there is a difference between the private and social costs, the impacts of these effects varies considerably, even among the staunchest supporters of

climate change.[3] Despite this uncertainty, some governments have established prices for CO_2 emissions, while others have not. The failure of governments to act uniformly has been a source of consternation for participants on either side of the debate, and global summits on climate change have not led to a resolution of the question.

While the European Union has established an emissions trading system, the two other members of the "Big Three" in CO_2 emissions[4] have yet to implement nationwide programs to impose a market price on emissions. The federal legislature of the United States introduced the Waxman-Markey Bill in the House of Representatives and the Kerry-Boxer Bill in the Senate in 2009. Both bills proposed a reduction in CO_2 emissions to 17% of 2005 levels by 2050. The Waxman-Markey bill passed in the House, but the Kerry-Boxer bill languished. In July 2010, Senate Majority Leader Harry Reid told the New York Times, in announcing that the Senate would not take up legislation to reduce carbon emissions, "We know that we don't have the votes."[5] The Chinese government has shown support for voluntary emissions reduction programs and stated national emissions reduction goals, but has not supported emissions prices.

This apparent inability for nations to agree on a market treatment for CO_2 emissions could be the result of a disagreement over the magnitude of the externality, or the costs and benefits associated with mitigating it, but there may be complications in the behavior of the marginal costs and benefits as well.

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[3] The IPCC Working Group II Report "Impacts, Adaptation, and Vulnerability" assigns levels of confidence to each statement regarding future impacts of climate change and states that: "The impacts frequently reflect projected changes in precipitation and other climate variables in addition to temperature, sea level and concentrations of atmospheric carbon dioxide. The magnitude and timing of impacts will vary with the amount and timing of climate change and, in some cases, the capacity to adapt."

[4] China, The U.S., and the European Union account for over 50% of the world's CO_2 emissions

[5] "Democrats Call Off Climate Bill Effort", New York Times, July 22, 2010

The provision of electricity is critical to life in the United States, and a better understanding of the effects and challenges of changes in the sector can lead to improvements in consumer and producer welfare.

CHAPTER 2
PRICE EFFECTS OF INDEPENDENT SYSTEM OPERATORS IN THE UNITED STATES ELECTRICITY MARKET

Introduction

Before the Federal Energy Regulatory Commission (FERC) issued its landmark Order 888 in April of 1996, the electricity generation, transmission, and distribution market in the United States had functioned largely within a vertically integrated monopoly structure for over 100 years. The opening paragraph of Order 888 reads:

> Today the Commission issues three final, interrelated rules designed to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers. The legal and policy cornerstone of these rules is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce. A second critical aspect of the rules is to address recovery of the transition costs of moving from a monopoly-regulated regime to one in which all sellers can compete on a fair basis and in which electricity is more competitively priced.[1]

FERC appears to believe that the vertically integrated structure in which the generator of electricity also controls the transmission of electricity is inefficient, and that this inefficiency leads to higher prices. The issuance of this order paved the way for numerous states to introduce plans to restructure their electric markets, with varying degrees of success. This movement began most notably in California, Texas, and a number of states in the Northeast, with the separation of the utility's generation from the transmission and distribution functions. To facilitate non-discriminatory access for all generators to the transmission grid, FERC conditionally approved the formation of five independent system operators (ISO) in 1997 and 1998 to oversee the deregulated wholesale power markets.

In December of 1999, FERC issued Order 2000, which stated:

[1] FERC Order 888, issued April 24, 1996, Page 1 (75 FERC ¶ 61,080)

> The Federal Energy Regulatory Commission (Commission) is amending its regulations under the Federal Power Act (FPA) to advance the formation of Regional Transmission Organizations (RTOs). The regulations require that each public utility that owns, operates, or controls facilities for the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in an RTO. The Commission also codifies minimum characteristics and functions that a transmission entity must satisfy in order to be considered an RTO. The Commission's goal is to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service.[2]

This Order suggests that FERC believed that the establishment of independent entities to control access to the electric transmission system would result in costs that are no greater than the costs that exist at the time of the order.

The focus of this paper is to identify tangible price effects as a result of the formation of RTOs and ISOs. These effects are critical to assessing the efficacy of this landmark regulatory policy. While there are structural differences[3] between the two types of organizations, their basic function of ensuring equal access for electric generators to the transmission grid and optimal dispatch of the generating system remain. Since that is the function analyzed in the paper, the terms ISO or RTO as used here are effectively indistinguishable.

An RTO can impart many benefits to the market in both the short term and long term. FERC Order 2000 identified five benefits that RTOs can offer: improved efficiencies in the management of the transmission grid, improved grid reliability, non-discriminatory transmission practices, improved market performance, and lighter-handed government regulation[4]. Through the optimization of the daily and hourly decisions of system dispatch over a wider geographic area than the existing system, the RTO may lower the system costs required to serve electric

[2] FERC Order 2000, issued December 20, 1999, Page 1 (89 FERC ¶ 61,285)

[3] For example, RTOs have been tasked by the FERC to ensure the long term reliability of the system by managing transmission investment. ISOs are nominally regulated by the Federal government, while RTOs govern themselves.

[4] FERC Order 2000, issued December 20, 1999, Page 70-71 (89 FERC ¶ 61,285)

load. By allowing non-discriminatory access to the transmission system, the RTO may also be able to incorporate lower priced resources that may not have enjoyed access to the market under a previous market regime, thus lowering system costs. Fabrizio, Rose, and Wolfram (2007) provide evidence that electric generators increase their operating efficiency in a market environment by reducing labor and nonfuel operating expenses, relative to operators in states that do not restructure their markets. An RTO may also be able to improve the reliability of the electric system by coordinating resource allocation and long term system planning. All of these benefits must be measured against the costs of operating and maintaining the RTO, and the costs incurred by market participants for compliance and regulation. However, since all costs related to the RTO are recovered through volumetric charges passed through to consumers of electricity served by that RTO, it is possible to assess the RTO's effect on system costs net of the RTO's own costs by examining the rates charged to customers. A change in prices, controlling for other factors, should signal either a net cost or net benefit associated with the RTO.

FERC is presently attempting to assess the costs and benefits of RTOs. In February of 2010, FERC issued a request for comments on a series of performance metrics for ISOs and RTOs[5]. This request for comment was the result of a 2008 report from the Government Accounting Office that requested that FERC work to develop metrics to track the performance of RTO operations and report this performance to the public. Once this data is collected, regulators will have better information with which to address the question, but the goal of this paper is to see if there is something that can be learned now, with the data available. Pricing metrics utilized by FERC include indicators of wholesale market price performance, but do not reflect the costs paid by retail utility customers. Any burden to the retail customer will include not only the

[5] 75 Fed. Reg. 7581 (2010)

wholesale market prices, but the utility's costs of compliance. As a result, FERC performance metrics account for some of the costs to retail customers, but do not address all of them. In an effort to assess the costs of maintaining a RTO, Greenfield and Kwoka (2010) have developed an econometric model of RTO costs dependent upon the geographic scale, scope of services provided, and age of the RTO. Such a model could be used to benchmark the relative cost effectiveness of these organizations. Kwoka, Pollitt, and Sergici (2010) have also presented evidence that forced divestiture as a result of electric restructuring has resulted in decreases in efficiency for electric distribution systems. Because these models do not address benefits, the question of whether RTOs have provided net benefits the consumers of electricity remains open.

This study employs a panel data set of the contiguous United States spanning the period 1990-2008 in an attempt to determine whether the establishment of RTOs has had an effect on the prices that consumers pay for electricity. The United States electricity market is particularly attractive for studying questions related to market structure. For roughly 100 years, most electric utilities in the United States were vertically integrated, providing generation, transmission, and distribution of electricity. Following the issuance of FERC Order 888, industry structure changed. Many states restructured their electricity markets, forcing the divestiture of the generation, transmission, and distribution components of the electric utilities in their state. Utilities in other states did not restructure, but ceded control of their transmission assets to independent entities, the RTOs and ISOs. A third group of states retained their vertically integrated structure. This paper exploits this diversity to study the effects of changes in market structure. The analysis concludes that the price effects of RTOs, when disentangled from the effects of electric restructuring, are not statistically significant, and these general results are robust to various specifications of the model. However, when the price effects for individual

classes of customers are considered, there may be some slight reductions in price for residential and industrial customers.

The remainder of the paper is organized as follows: Section 2 consists of a review of the existing literature, Section 3 describes the data used in the analysis, Section 4 is a description of the estimation models used, Section 5 discusses the results of the analysis, and Section 6 contains some concluding remarks.

Existing Literature

Coase (1937) addressed the question of why individuals organize into firms, observing that the degree of vertical integration varied greatly among types of industries and types of firms. Since individuals were always free to interact with the market in the absence of firms, Coase concluded that firms arise when the costs of interacting with the market exceed the costs of interacting within an organization. So, if the regulators of a particular industry decided that the costs of interacting within an organization would exceed those of the market, they might restructure the firms in the industry in order to reduce transaction costs.

Grossman and Hart (1986) have argued that the literature on transaction costs emphasized the conclusion that nonintegrated relationships can be inferior to relationships with complete contracts. However, they assert that this is not due to the nature of the nonintegrated relationship itself, but because of the presence of incomplete contracts. They pointed out that this argument in the existing literature has assumed that integration leads to complete contracts, which may not be the case. They further argue that the proper comparison is that between contracts that allocate rights of ownership, residual rights, to one party and contracts that allocate them to another. They conclude that when it is too costly to specify a list of particular rights that one party desires over another party's assets, it may be optimal to purchase all rights.

Previous studies in the electricity area have focused on the question of whether restructuring of the electricity market itself has led to changes in delivered electricity prices. Kwoka (2006) presents a review of a number of these studies. He finds that all are plagued by two underlying problems: the endogeneity issues related to the decision to restructure the electricity market, and the confounding effects of settlement agreements between the states and the utilities in the state that were necessary to enable each state's restructuring plans. The particular terms of these settlement agreements varied considerably by state, but contained two common elements. The first element was some form of retail rate control, either a rate freeze that kept rates at current levels for a designated period of time, or a prescribed schedule of future rates based on current rates. Most often, the first year in the schedule mandated a rate decrease, and this decrease often persisted beyond the first year. The second element was a mechanism to recover the value of stranded assets, or to recover costs not recovered under the rate agreement. Restructuring in Pennsylvania, for example, was accompanied by the imposition of retail rate caps on the privately-owned utilities. The expiration of the rate caps for PPL Electric Utilities in January of 2010 was accompanied by rate increases of 30%. This dramatic increase in electric prices suggests that the realized prices in the years following the restructuring agreement did not reflect the market price for electricity in Pennsylvania. The states of Maryland and California experienced similar price increases upon the expiration of imposed price caps, so the experiences of the state of Pennsylvania are not unique. Clearly, some degree of 'cost savings' from electric restructuring was simply a temporal subsidy, though it is not yet clear how much, as this transition cost recovery continues in many states, and the methods used to impose this subsidy were heterogeneous across states. Because temporal subsidies have been used to shift costs, the full effect of these subsidies is unknown and the effect of restructuring on costs is difficult to

determine. Therefore, any analysis utilizing electricity prices in restructured states will be tainted by those confounding effects, as well as by endogeneity issues related to the decision to restructure the electricity market.

The present study frames the question differently to avoid those confounding effects. Rather than attempt to explain the changes in price wrought by electric restructuring, which is composed of two inter-related effects[6], this paper focuses on whether there have been changes in price as a result of the formation of ISOs or RTOs. A map of the current footprint of these organizations is shown in Figure 2-1.

Figure 2-1. Regional Transmission Organizations in North America[7]

[6] The two effects are the effect of the change in market structure as well as the effect of the rate agreement used to facilitate electric restructuring.

[7] From http://www.ferc.gov/industries/electric/indus-act/rto.asp

Using a panel data set of the 48 contiguous United States, this paper utilizes a treatment effects model in first differences to determine whether there have been changes in delivered electric prices as a result of the establishment of RTOs. To avoid the confounding effects of electric restructuring, the model is initially estimated with the full panel data set as a benchmark, and then again without the 16 states that have restructured their electric markets. Of the remaining 32 states, 12 are served by one or more RTOs. Table 2-1 shows the average nominal price of electricity for each of these state groups.

Table 2-1. Mean and standard deviation of nominal electricity price for each state group

Restructuring Status	ISO Status	N	Nominal Price
Restructured States	Before ISO Implementation	150	8.09
			1.91
	After ISO Implementation	154	9.98
			2.67
Non-Restructured States Served by ISOs	Before ISO Implementation	126	5.96
			0.93
	After ISO Implementation	102	6.81
			1.67
Non-Restructured States Not Served by ISOs		380	6.14
			1.29

Table 2-1 illustrates the endogeneity issue raised by Kwoka. The states that restructured their electricity markets exhibited higher prices, on average, than the states that did not. However, among the states that did not restructure their electricity market, there is little difference, on average, in price level between the states that were eventually served by ISOs and those that were not. Therefore, by considering only the states that have not restructured their electric markets, this paper estimates whether there have been price effects due to the establishment of RTOs, in the absence of restructuring agreements.

Data

The data used in this paper are annual data for the 48 contiguous United States, spanning the period 1990 through 2008. The data for the study are primarily derived from reports and survey forms prepared by the United States Department of Energy's Energy Information Administration (EIA). The EIA is mandated by Congress to collect survey data from electric utilities in the United States. These data are collected on a variety of forms spanning electric utility operations. The EIA-860 report consists of generator-specific data such as generating capacity and energy sources. The EIA-861 and EIA-826 reports contain utility-specific data on sales and revenues by customer class. The EIA-923 report contains utility-specific data on electricity generation and fuel consumption. This utility- and generator-specific data is aggregated by state as a component of the EIA's State Energy Data System, the primary data source for statewide generation and prices in this study. Prices used in this study are average prices across customer classes, as well as for broad customer classes, calculated by dividing revenue by the sales volume. State-level data on annual heating and cooling degree days is available from the National Climatic Data Center, which population-weights the heating and cooling degree days collected from individual climate monitoring stations. Heating and cooling degree days are functions of average daily temperature often used to explain demand for electricity (Papalexopoulos and Hesterberg, 1990). They are the aggregate of the average daily temperatures either above (cooling) or below (heating) 65 degrees Fahrenheit. For example, if the average daily temperature is 70 degrees, then that day is said to have 5 cooling degrees[8]. These degree days are then aggregated annually or monthly. Data on annual population by state

[8] If, for example, half of a state's population experiences 70 degree temperatures and half of the population experiences 74 degree temperatures, then the National Climatic Data Center will record 7 cooling degrees for that state, for that day.

is from the U.S. Census Bureau. Data on per capita income by state is from the U.S. Department of Commerce, and is used as a proxy for heterogeneous economic conditions within each state. Data regarding state participation in electric restructuring activities is available from EIA[9], FERC, and the individual state regulatory agencies. Finally, the membership of state utilities in RTOs is available from EIA, FERC (as seen in Figure 2-1), and the individual RTOs.

The Model

The paper presents a model of the average electricity prices paid per kilowatthour (kWh) of consumption by the customers in each state, and tests the treatment effect of RTOs on that price. The effects of RTOs are not limited to prices, however. The centralization of dispatch and system planning decisions may have impacts beyond electricity revenues, such as on the overall system reliability. The effects of the RTOs on system reliability are much more difficult to assess, as most reliability data is proprietary. Further, the RTOs may be able to optimize the decisions regarding power plant investment within its region of responsibility, but its effects may not yet be seen. Thus, this paper studies the impact that RTOs have through the retail rates charged to customers. This is an important metric, as the portion of FERC Order 2000 cited above specifically states the Commission goal of lowest possible prices.

The average revenue per kWh of electricity for each state *i*, in a given year *t* can be expressed by the following panel equation:

$$Price_{it} = \alpha_i + \beta_0 Sales_{it} + \beta_1 PCoal_{it} + \beta_2 PGas_{it} + \beta_3 \%Hydro_{it} + \beta_4 \%Nuc_{it} + \beta_5 RTO_{it} + u_{it} \quad (2\text{-}1)$$

where:

[9] For example, http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html

Price	Nominal state electricity revenues per kWh in cents/kWh
Sales	Electricity sales in MWh
PCoal	Nominal state price of coal in $/MMBtu
PGas	Nominal state price of natural gas in $/MMBtu
%Hydro	Percent of electric generation from hydroelectric sources
%Nuc	Percent of electric generation from nuclear sources
RTO	Whether the majority of the electric customers in the state are served by a utility that belongs to an RTO

The mean and standard deviation for these variables is given for the entire sample, as well as three cohorts, in Table 2-2.

Table 2-2. Mean and standard deviation for model variables

	Entire Sample	Restructured States	States that Did Not Restructure Electric Industry	
			RTO States	Non-RTO States
Price (cents/kWh)	7.16	9.05	6.34	6.14
	2.25	2.51	1.38	1.29
Sales	6.75e07	9.28e07	4.16e07	6.28e07
	6.09e07	8.30e07	2.98e07	4.39e07
Coal Price	1.36	1.58	1.05	1.37
	0.58	0.61	0.46	0.53
Natural Gas Price	4.31	4.31	4.45	4.22
	2.42	2.49	2.39	2.38
% Hydro	11.10%	9.84%	8.68%	13.56%
	20.83%	18.89%	15.81%	24.44%
% Nuclear	18.43%	22.72%	18.39%	15.03%
	18.53%	18.80%	21.36%	15.58%
N	912	304	228	380

The variable α represents the fixed effects of the model, or the heterogeneous characteristics of the state that contribute to the prevailing electricity price in the state. The price

of electricity in a state is influenced by factors such as the types of units used to generate electricity, the price and availability of fuel, the geographic proximity to these resources, the effects of geography on the costs of electricity transmission and distribution, heterogenous ratemaking standards that might apply to that state, or the degree to which ratemaking authority is centralized[10]. Because generating units are long-lived assets, the composition of the generating fleet will change little over time leading to stability in the structure used to produce electricity. As a result, price levels might be expected to differ by state, and these differences might be expected to persist. Figure 2-2 illustrates the electricity prices in the data set for three sample states. Idaho's low prices are the result of the abundance of inexpensive hydropower resources in the region. Georgia relies primarily on coal and nuclear generation and thus experiences higher prices than Idaho. Connecticut relies on nuclear and natural gas generation, with no access to lower priced coal generation, and therefore had the highest prices of the three states. The centralization of ratemaking authority is also a source of heterogeneity, with each state served by some combination of investor-owned, municipally-owned, and cooperative utilities. However, the ownership status of these utilities rarely changes, so this heterogeneity will be relatively stable over the sample period.

[10] State public utility commissions typically have ratemaking authority over only investor-owned utilities, while municipally-owned utilities are governed by the municipalities themselves, and cooperative utilities are governed by the customers they serve.

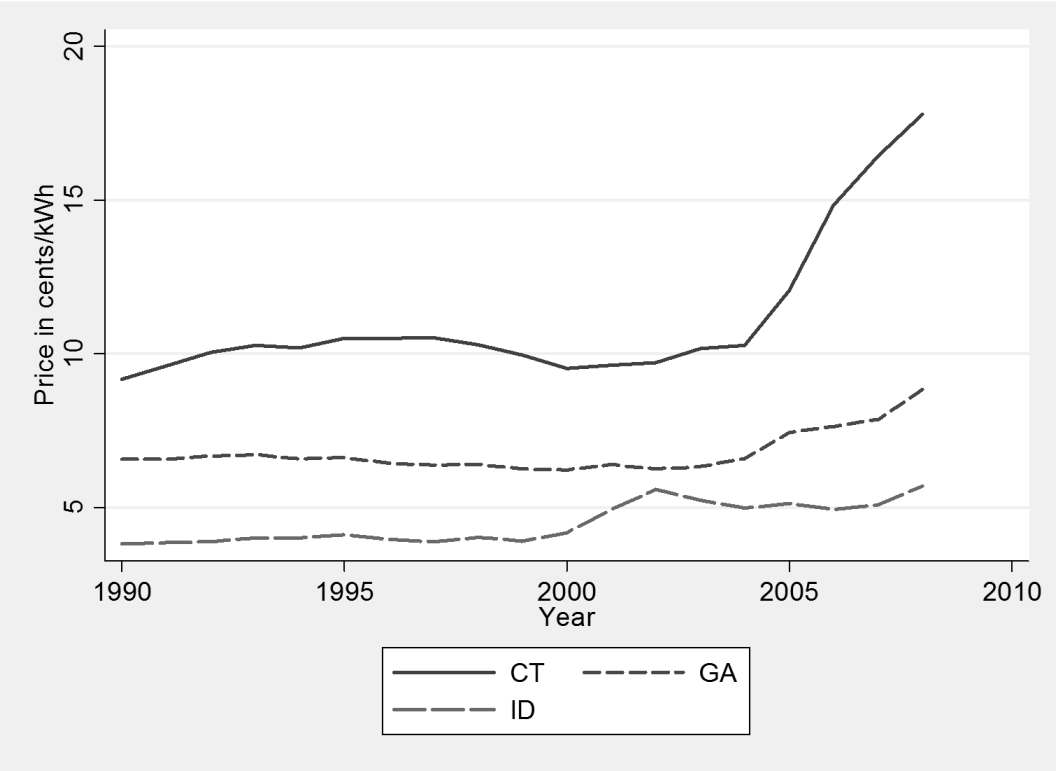


Figure 2-2. Comparative state electricity prices

The heterogeneous effects of this variable α are removed by estimating the model in first differences. Further, the variables *Price*, *Sales*, *PCoal*, and *PGas* are transformed by taking logs, so that the variables in the equation, with the exception of the treatment, all represent annual percent changes. The estimation equation then becomes:

$$\Delta lnPrice_{it} = \beta_0 \Delta lnSales_{it} + \beta_1 \Delta lnPCoal_{it} + \beta_2 \Delta lnPGas_{it} + \beta_3 \Delta\%Hydro_{it} \qquad (2\text{-}2)$$
$$+ \beta_4 \Delta\%Nuc_{it} + \beta_5 \Delta RTO_{it} + \beta_6 \Delta RTO_{it-1} + \beta_7 \Delta RTO_{it-2} + u_{it}$$

Lagged observations of the RTO variable are also included in the estimated model, as the effects of the RTO may not materialize (or fully materialize) in the year of its inception. The first

lag will be equal to 1 if the utilities in the state became members of an RTO in the previous year, and the second lag equals 1 if two years prior.

One further refinement to the model is necessary. Unless the price elasticity of electricity demand is zero, the electricity sales variable is endogenous in the price equation. While other authors have estimated the price elasticity of demand for electricity[11], that question is beyond the scope of this paper. As long as the price elasticity differs from zero, it is important for the specification of this model. Therefore, the endogeneity of the electricity sales variable is tested using the instrumental variables heating and cooling degree days, state per capita income, and state population. Even if the price of electricity has an effect on sales, it should not have an effect on the weather, income or the population of the state, so these variables are exogenous. The reduced form equation for *ΔlnSales* is estimated and the residuals are included as explanatory variables in Equation 2-2. The coefficient on this variable is significant[12], and so Equation 2-2 is estimated using 2SLS with the instrumental variables heating and cooling degree days, state per capita income and state population for *ΔlnSales*.

The sign of the *ΔlnSales* coefficient might be positive or negative. Increased demand for electricity increases the expenditure on fuels required to produce electricity and may result in the utilization of higher cost generating units, which would have the effect of increasing price. However, utilities generally recover some amount of fixed costs through variable charges, so a decrease in sales could also have the effect of raising prices overall, as any fixed costs need to be recovered over a smaller volume of sales. Increasing fuel prices, the primary variable cost of electricity production, should also cause prices to increase, so the signs on *ΔlnPCoal* and

[11] See, for example, Bernstein and Griffin (2005)

[12] The details of the reduced form estimation are included in Appendix A

ΔlnPGas coefficients should be positive, as many utilities recover fuel expenditures as they are incurred through fuel adjustment charges in their retail rates. The variable costs associated with the production of hydroelectricity are very low, but the availability of hydroelectricity varies with year to year levels of precipitation, realized as either rainfall or accumulated snow pack. However, when the electricity is available, it is available at much lower variable costs. Therefore, the sign on *Δ%Hydro* is expected to be negative, as increased volumes of hydroelectricity should displace more expensive generating resources. The sign on *Δ%Nuc* should also be negative, as increased availability of low priced nuclear generation should result in lower electricity prices.

Results

The results of the estimation of Equation 2-2 are shown in Table 2-3.

Table 2-3. 2SLS estimates with entire sample

Variable	Coefficient
Constant	0.0180***
	(0.0029)
ΔlnSales	-0.0504
	(0.0899)
ΔlnPCoal	0.1650***
	(0.0279)
ΔlnPGas	0.0209***
	(0.0078)
Δ%Hydro	-0.1756***
	(0.0553)
Δ%Nuc	-0.0143
	(0.0183)
RTO	-0.0200**
	(0.0089)
RTO_{t-1}	-0.0284***
	(0.0092)
RTO_{t-2}	-0.0043
	(0.0126)

R-squared of 0.14
Robust standard errors clustered by state in parentheses
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

The coefficient on sales is negative, but not significantly different from zero. Since the dependent variable represents values on the average cost curve, this suggests that the utilities are operating close to the minimum point on the curve. The coefficients for the fuel prices both have the expected signs and are statistically significant at the 1% level, though the electricity price is eight times more sensitive to a 1% increase in coal prices than to a natural gas price increase. The broad result that electricity prices are more responsive to changes in coal price than natural gas prices is consistent with Mohammadi (2009), although he finds that coal price elasticity is

roughly twice that of natural gas. This result offers further insight into the problem of modeling electricity prices in general. It is a common approach, in modeling electricity prices, to form a fossil fuel price index[13] and use it as a proxy for fuel costs. The result that the coefficients for natural gas prices and coal prices are significant and distinct in this specification suggests that modeling fuel prices in this manner is conveying information that would be unavailable if the fossil fuel index approach is adopted. Increased availability of hydroelectricity causes the price to decrease, and this decrease is significant. Finally, as indicated by the sum of the coefficients on the RTO and RTO_{t-1} variables, electricity prices seem to fall by about 4.8% during the first two years of an RTO's existence. The coefficient associated with the RTO_{t-2} variable is not statistically significant, and further lags of the variable yield similar results. This indicates that if an RTO is going to have a price impact on consumers, it occurs in the first two years of its existence. This 4.8% decrease is statistically significant and interesting, because it is at the lower range identified by Joskow (2006), who estimates the price effects of electric restructuring, utilizing a different data set and methodology, to be 5% to 10%.

However, as noted by Kwoka (2006), the effects of restructuring settlements and any imposed rate caps that accompanied those settlements can act as confounding factors, by masking the market prices that might otherwise exist if not for the restructuring agreement. That is, when the equation is estimated with the full sample, the effects of RTOs are indistinguishable from the effects of these rate agreements, if membership in an RTO accompanies the restructuring. It would be preferable to simply account for these rate agreements with additional variables, but the form of these agreements, such as the length of time that rate controls are put in place, the restrictiveness of these controls, and the period over which these deferred costs are

[13] This index is essentially a weighted average of coal and natural gas prices, as the states in the sample do not use appreciable quantities of petroleum to generate electricity.

recovered, differs greatly from state to state, making the quantification of their effects difficult. Therefore, the best way to control these effects is to remove them altogether.

To remove this confounding effect, the equation is estimated with only the sample of states that have not restructured their electric industry. This means that the sample is free of any of the confounding effects of rate agreements on electricity prices, and should truly reflect the effects of RTOs, controlling for other factors. Note that membership in an RTO does not require restructuring of the electric utility, as the RTO does not assume ownership of the transmission and distribution assets of the utility, so the sample includes states that are within RTOs, but have not restructured their electric industry. The results of the estimation of equation (2) with this restricted sample are shown in Table 2-4.

Table 2-4. 2SLS estimates excluding states that have restructured their electric industry

Variable	Coefficient
Constant	0.0141***
	(0.0033)
ΔlnSales	-0.0561
	(0.1007)
ΔlnPCoal	0.1775***
	(0.0366)
ΔlnPGas	0.0263***
	(0.0081)
Δ%Hydro	-0.2053***
	(0.0742)
Δ%Nuc	0.0549
	(0.0553)
RTO	-0.0127
	(0.0086)
RTO_{t-1}	-0.0127
	(0.0106)
RTO_{t-2}	0.0043
	(0.0095)

R-squared of 0.21
(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

Notice that the signs and significance of most of the variables remains unchanged when the model is estimated with this subset of the data. The magnitudes of the coefficients are consistent as well. However, the variables corresponding to the establishment of an RTO and the effects of that RTO one year later have changed considerably. First, the magnitude of the variables related to the RTO has fallen by roughly half, and second, the precision of their measurement has decreased. Neither variable is significant at even the 10% level. Therefore, by eliminating from the sample those 16 states that have restructured their electric industry, the price effects of an RTO are reduced from approximately 4.8%, an effect significantly different from 0%, to 2.5%, but not significantly different from 0%. This suggests that most of the realized price reductions observed in the initial estimation are not due to the change in the market structure, but the form of the restructuring agreements in the states that chose to restructure their markets. Therefore, if there are any cost savings that result from the establishment of RTOs in the absence of electric restructuring, they are not significantly different from zero.

Alternate specifications of this model are tested, both as a check on the robustness of the results as well as a way to relax certain assumptions of the original specification of the model. First, the effect of RTO membership on real prices instead of nominal prices is considered. Using the annual consumer price index from the Department of Labor's Bureau of Labor Statistics, all of the electricity and fuel prices are restated in real terms. Replacing nominal prices with real prices decreases the magnitude of the price effects, once the effects of inflation are removed, but does not change the results regarding statistical significance.[14]

Second, the original model, as specified, assumes that the marginal effect of changes in fuel price does not vary by state. However, because the availability of resources necessary to

[14] Estimation details are available upon request from the author.

generate electricity varies with individual state geography, the degree to which each state relies on different types of fuels changes. Therefore, this assumption that marginal effects are constant across states may not be valid. Therefore, another specification of the model is estimated with interaction terms between each state and the annual change in the price of coal and natural gas in that state.

Table 2-5. 2SLS estimates with entire sample and interaction terms between state and fuel price

Variable	Coefficient
Constant	0.0175***
	(0.0030)
ΔlnSales	-0.1015
	(0.0955)
Δ%Hydro	-0.1819***
	(0.0527)
Δ%Nuc	-0.0026
	(0.0527)
RTO	-0.0288***
	(0.0086)
RTO_{t-1}	-0.0325***
	(0.0097)
RTO_{t-2}	0.0017
	(0.0126)

R-squared of 0.38
(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

The 96 coefficients for the state and fuel price interaction have been omitted from Table 2-5 for the sake of parsimony, but a Wald test rejects the hypothesis that the coefficient of each state with respect to coal prices are equal at the 1% level, and a test of the coefficients on gas prices yields similar results. For illustrative purposes, selected coefficients are listed in Table 2-6[15].

[15] The coefficients for all 96 interaction terms are available from the author upon request.

Table 2-6. Selected coefficients on the interaction between state and fuel prices

State	Coefficient
Change in log coal prices	
Alabama	0.3910***
	(0.0081)
Florida	0.4741***
	(0.0136)
Georgia	0.5288***
	(0.0226)
Minnesota	0.2633***
	(0.0093)
Change in log natural gas prices	
Colorado	0.0678***
	(0.0007)
Louisiana	0.2260***
	(0.0015)
Oklahoma	0.1384***
	(0.0101)
Texas	0.1717***
	(0.0062)

(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

This specification of the model controls for the heterogeneity of each state's sensitivity to fuel prices, and the coefficients are consistent with the degree to which these states rely on these fossil fuels. As of 2008, 37% of Alabama's generating capacity was coal-fired, as was 18% of Florida's generating capacity, and 36% of Georgia's and Minnesota's. Colorado relies on natural gas for 44% of its generating capacity, while Louisiana, Oklahoma, and Texas are much more reliant on gas for 76%, 65%, and 69% of their capacity, respectively. It is not surprising, then, that the electricity prices in these states would be sensitive to the prices of these fuels. The addition of these variables does not change the results of the analysis, however, as shown in the restricted sample regression results in Table 2-7.

Table 2-7. 2SLS estimates with restricted sample and interaction terms between state and fuel price

Variable	Coefficient
Constant	0.0191***
	(0.0026)
ΔlnSales	-0.0848
	(0.0957)
Δ%Hydro	-0.1853**
	(0.0752)
Δ%Nuc	0.0190
	(0.0546)
RTO	-0.0152*
	(0.0089)
RTO_{t-1}	-0.0009
	(0.0084)
RTO_{t-2}	0.0077
	(0.0057)

R-squared of 0.44
(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

The individual state interaction terms change slightly, but remain largely consistent between the two samples. Once again, the effect of the RTO is reduced dramatically, as is the precision with which it is measured. However, with this specification, a reduction of approximately 1.5% in realized electricity prices is observed, and this result is significant at the 10% level.

Finally, the state data set also includes prices and sales reported by broad customer class (i.e. residential, commercial, and industrial customers). To see if benefits from RTOs have accrued to particular customer classes, Equation 2-2 is estimated using the prices and sales for each class of customer and the results are reported in Table 2-8. The coefficients are similar in sign and magnitude to the ones in Table 2-4, but now there are two statistically significant results for the RTO variables. The first is a 1.44% decrease in prices for residential customers in the first

year of the RTO's existence. The second is a 2.49% decrease in prices for industrial customers in the second year of the RTO's existence. This provides evidence that for certain types of customers, the change in market structure may be producing tangible cost benefits. Residential customers are typically voters, so this group exerts political influence, and industrial customers are important consumers of electricity, so the price benefits for these groups may not be surprising. However, given that roughly 35 different organizations representing large industrial users of electricity contributed to the final version of FERC Order 888, these customers have not seen a sizable reduction in price.

Table 2-8. 2SLS estimates by customer class excluding states that have restructured their electric industry

Variable	Residential	Commercial	Industrial
Constant	0.0172***	0.0160***	0.0064
	(0.0028)	(0.0043)	(0.0054)
ΔlnSales	-0.1175	-0.2058*	0.0483
	(0.0830)	(0.1099)	(0.1417)
ΔlnPCoal	0.1355***	0.1523***	0.2830***
	(0.0325)	(0.0414)	(0.0897)
ΔlnPGas	0.0054	0.0075	0.0616***
	(0.0075)	(0.0104)	(0.0195)
Δ%Hydro	-0.0302	-0.0318	-0.6212**
	(0.0539)	(0.0908)	(0.3020)
Δ%Nuc	0.0610	0.0443	0.0051
	(0.0416)	(0.0685)	(0.0932)
RTO	-0.0144**	-0.0153	-0.0031
	(0.0070)	(0.0150)	(0.0135)
RTO_{t-1}	-0.0065	-0.0186	-0.0249*
	(0.0097)	(0.0139)	(0.0143)
RTO_{t-2}	0.0103	0.0125	0.0051
	(0.0073)	(0.0081)	(0.0149)

(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

Conclusion

When FERC established rules to change the structure of the electricity market, it did so under the belief that the existing system was inefficient, and that the change in structure would provide benefits to consumers. Ten years after these original orders, the question regarding benefits of the changes in market structure was raised by the Government Accounting Office, leading to a FERC Request for Comment on the establishment of performance metrics for ISOs and RTOs. Once these data have been collected, greater insight into the net benefits of the establishment of ISOs and RTOs may be possible.

However, the present study provides some immediate insight into this important issue. Utilizing a panel data set of the United States over the past 18 years, this paper estimates equations for annual percentage changes in electricity price, and attempted to identify the degree to which membership in an RTO affects costs. There is a significant effect, a decrease of 4.8% over two years, when estimating these price changes with the entire data sample. However, the entire sample includes the effects of rate agreements that accompanied restructuring agreements in states that chose to restructure their market. When the equation is estimated excluding the states that restructured their electric industry, the significance of the price change disappears. Therefore, if ISOs and RTOs have led to changes in the price of electricity, then these changes are indistinguishable from zero or may only apply to certain classes of customer. However, there may be other benefits of RTOs relating to reliability of electricity service or the optimization of long term resource planning that are not estimated here. The question of whether RTOs have influenced system reliability or the long term planning process would be interesting avenues for further research. However, given the time and effort required to comply with the changes in market structure necessitated by FERC rules, it is worth asking the question whether all of this effort has provided tangible benefits to electricity consumers at least in terms of lower prices.

CHAPTER 3
THE IMPACT OF THE TRANSPARENCY OF WHOLESALE MARKETS ON MARKET PARTICIPATION: THE CASE OF THE U.S. ELECTRICITY INDUSTRY

Introduction

On December 20, 1999, the Federal Energy Regulatory Commission (FERC or "the Commission") issued Order No. 2000 in Docket No. RM99-2-000, a docket opened to explore the role of Regional Transmission Organizations (RTO) in the restructured electricity marketplace. The role of an RTO is to administer the electric transmission system, ensuring open access to the grid for all electricity generators. The FERC noted that since FERC Order 888 was issued in 1996, trade in the bulk electricity markets had increased significantly. FERC also noted that during the Notice of Proposed Rulemaking process for the instant docket, the Commission had "reviewed evidence that traditional management of the transmission grid by vertically integrated electric utilities was inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets, and that continued discrimination in the provision of transmission services by vertically integrated utilities may also be impeding fully competitive electricity markets."[1] FERC further enjoined utilities, state officials, and affected interest groups to voluntarily develop RTOs. Despite the urging of FERC, there remain substantial portions of the United States electricity grid that are not administered by RTOs or Independent System Operators (ISO).

Coase (1960) observed that there are costs involved in carrying out transactions in the market, such as "to discover who it is that one wishes to deal with, to inform people that one wishes to deal and on what terms, to conduct negotiations leading up to the bargain, to draw up

[1]FERC Order 2000, issued December 20, 1999, Page 2 (89 FERC ¶ 61,285)

the contract …".[2] Milgrom and Roberts (1992) categorize these costs as either coordination or motivation costs. They define coordination costs as the need to determine the price and other parameters of the transaction, make the existence of buyers and sellers known to one another, and bring buyers and sellers together. Motivation costs arise from incomplete and asymmetric information and imperfect commitment. The wholesale market for electricity, where the relevant product is one kilowatthour (kWh) of electricity delivered to a particular location at a particular point in time, is prone to coordination costs, as the product has a very short useful life. RTOs and ISOs can have an explicit influence on the coordination costs in the wholesale electricity market, but the direction of that influence is not always clear. One way in which RTOs can influence coordination costs is by publishing wholesale electricity prices in a manner in which any interested party can access them[3]. This paper employs a panel data set of United States electric utilities spanning the period 1990-2009 to investigate whether the existence of a transparent wholesale market increases the degree to which an electric utility participates in the wholesale market. I find that privately-owned utilities and larger utilities increase their participation in a transparent wholesale market, while participation of municipally-owned utilities is only slightly affected. This indicates that the distribution of the benefits afforded to participants in market administered by RTOs is not uniform across all market participants.

The remainder of the paper is organized as follows: Section II provides a discussion of the costs and benefits of RTOs, Section III provides a review of related literature, Section IV describes the data utilized, Section V describes the empirical model and estimation methodology, Section VI reports the results of the estimation, and Section VII offers concluding remarks.

[2] Coase (1960) p. 15

[3] Further discussions of these costs and benefits follow in Section II.

Costs and Benefits of RTOs

One way that ISOs and RTOs can influence the development of electricity markets is by providing a transparent wholesale market, which can be defined as a market in which the prices for a unit of electricity delivered to a given location at a given point in time are posted in a manner that is easily accessible by any interested party, such as on a public web site.[4] Consider the case of a naive electric utility, Alpha, operating as an island, isolated from the electricity grid around it. The utility dispatches its generating units to supply electricity to its customers, and attempts to do so in a manner that optimizes performance, typically measured in terms of least cost or some standard of reliability. If electricity demand and the criteria under which the utility optimizes its portfolio (say, least cost) are taken as exogenous, then the utility's only task is to determine which of its generating units will be dispatched at any given time. Alpha assesses the hourly marginal costs of its generating units, considers any constraints related to the units' availability or operating characteristics, determines how much electricity it must supply, and dispatches units sufficient to meet the prevailing demand at the least possible cost.

Now consider the existence of a second electric utility, Beta, physically interconnected to Alpha in a neighboring area. Operating as an island, Beta faces the same decision as Alpha. However, if both utilities seek to minimize costs, and in a particular hour there is a difference between the utilities' marginal costs of generation that is greater than the cost of transmission from Beta to Alpha, then the opportunity for Pareto improvement exists. If Alpha has a higher marginal cost of generation than Beta in a given hour[5], then Beta can generate that marginal kWh

[4] Per Bakos (1998). For an example from the Midwest ISO, see https://www.midwestiso.org/MARKETSOPERATIONS/REALTIMEMARKETDATA/Pages/LMPContourMap.aspx

[5] This might be due to a difference in the fuel used to generate the electricity or the efficiency with which the fuel is used by the marginal generating unit of each utility.

and sell to Alpha at a price somewhere between their respective marginal costs, and both utilities have lowered their effective average costs of generation; Alpha by buying the marginal kWh at less than it would cost to generate it with its own units and Beta by realizing sales revenue greater than the cost to generate the marginal kWh.

But the costs that must be incurred in order to achieve this benefit are not limited to the cost of any transmission and the transaction itself. As Milgrom and Roberts observe, coordination costs also arise. Each utility must expend resources to gather information about the electricity system around it. First, each must gather information regarding the number of potential trading partners. Second, each needs information regarding the costs and availability of electricity in any given hour, for every one of those potential trading partners, to identify profitable trading opportunities. Third, each needs to know how to make the arrangements necessary to have that electricity delivered to the purchasing utility system if a transaction is agreed upon. Before the advent of RTOs and ISOs, the first and third tasks were often performed by roughly 140 regional balancing authorities (Joskow 2005), organizations registered by the North American Electric Reliability Corporation (NERC) to integrate future resource plans, maintain the balance between load, interchange, and generation, and support real time interconnection frequency for a given area. The second function was accomplished primarily through bi-lateral contact between utilities, though confederations of utilities also existed. For example, before ISOs and RTOs existed, the Orlando Utilities Commission, the City of Lakeland, and the Florida Municipal Power Agency formed the Florida Municipal Power Pool in 1988 to centrally commit and dispatch all of the pool members' generating resources to meet the pool's load obligations in the most economical manner.

By establishing a transparent wholesale market place, however, the RTO can fulfill the second task for the utility, either by maintaining a centralized databank of hourly prices, or by collecting hourly bids and offers from utilities interested in participating in the market. While the RTO can lower the costs required to gather this information, other costs to participate in this market still exist. Utilities must incur costs in order to conform to the rules and procedures of this wholesale market, and the ability to trade with utilities that are members of other RTOs may be constrained. In a survey of RTO cost/benefit studies, Eto, Lesieutre, and Hale (2005) report that while utilities will incur costs to participate in these markets, these costs had not been explicitly studied. Additionally, Newell and Spees (2011) find that gaps in realized sales of electricity capacity[6] across the PJM/MISO border are caused by institutional barriers. These barriers include difficulty in obtaining long term firm transmission service to support capacity sales, and energy market must-offer requirements that impose risks on capacity importers. Participation in these markets also imposes educational burdens on utilities. In the PJM Interconnection, a prominent ISO, the manuals describing the administrative, planning, operating, and accounting procedures number over 3000 pages in 34 separate volumes. Therefore, there are countervailing factors that may influence the utility's willingness to participate in this wholesale market.

Related Literature

The majority of the existing literature on electricity market restructuring has focused on the impacts of the restructuring itself. Kwoka (2006) reviews a number of studies on the price effects of electricity restructuring, and finds that they are plagued by the endogeneity of the treatment variable, electric restructuring, as the states with higher prices tended to restructure their electric industry. He also finds that it is difficult to disentangle the two effects of

[6] The capacity product in the electricity industry is the ability to generate electricity on demand, but not the electricity itself.

restructuring, the change in market structure and the effects of the rate agreements that accompanied restructuring. Fabrizio, Rose, and Wolfram (2007) examine the effects on restructured markets on electric generators and find increases in operating efficiency through reductions in labor and nonfuel operating expenses. Kwoka, Pollitt, and Sergici (2010) study electric distribution systems and find that forced divestiture as a result of electric restructuring has resulted in decreases in efficiency in distribution. Hogan (1995) argues that the ISO must be actively involved with the operation of the wholesale market and system dispatch. However, little empirical work has been done to assess the benefits of the RTOs and ISOs themselves.

Blumsack (2007) outlined the problem of evaluating the efficacy of RTOs and found that the metrics used to evaluate them were incomplete and not objective. He proceeded to enumerate nine areas on which evaluation metrics should focus. Davis and Wolfram (2011) studied the changes in operating efficiency of nuclear power plants in the United States and found that those operating in competitive wholesale markets increased their efficiency by 10%. Fabrizio (2012) studied the make or buy decisions of 240 investor-owned electric utilities from 1990 to 2007 and found that utilities in ISOs tended to meet increases in demand with more purchased power than non-ISO members. Outside of the electricity industry, Garicano and Kaplan (2000) have studied the changes in transaction costs as a result of business-to-business e-commerce and find that the Internet reduces coordination costs.

The question of the effects of market transparency has been well studied in the finance literature. The Securities and Exchange Commission (1994) stated that: "The Commission has long believed that transparency – the real-time, public dissemination of trade and quote information – plays a fundamental role in the fairness and efficiency of secondary markets"[7].

[7] Securities and Exchange Commission (1994), Page IV-1

Pagano and Roell (1996) studied stylized trading systems with differing degrees of transparency and found that while greater transparency lowered trading costs for uninformed traders on average, it did necessarily lower them for every size trade. Madhavan (1996) demonstrated that market transparency can increase price volatility and lower market liquidity, but that these effects disappear in markets that are sufficiently large.

Chandley and Hogan (2009) point out that "part of the purpose of RTO design was to facilitate trading"[8], and show that the day ahead net exports from the Midwest to the PJM region tripled when American Electric Power became a member of PJM in October of 2004.[9] FERC Order 2000 identified five benefits that RTOs can offer, relative to the existing market structure: improved efficiencies in the management of the transmission grid, improved grid reliability, non-discriminatory transmission practices, improved market performance, and lighter-handed government regulation.[10] This study examines whether utilities within RTOs participate more in the wholesale electricity markets, relative to utilities outside of RTOs, either due to improved efficiencies in grid management or non-discriminatory transmission practices.

Data

The primary data source for this study is the Form 861 database compiled by the U.S. Department of Energy's Energy Information Administration. The reporting of information collected on the Form 861 is an annual requirement for all privately and publicly owned electric utilities in the United States and its territories. Data collected includes the quantity of wholesale and retail purchases and sales, revenues, number of customers, annual system peak load, as well as information on demand-side management programs, green pricing and net metering programs,

[8] Chandley and Hogan (2009), Page 33

[9] Chandley and Hogan (2009), Page 34

[10] FERC Order 2000, issued December 20, 1999, Page 70-71 (89 FERC ¶ 61,285)

and distributed generation capacity. The utilities also report their control area operator on the form, which allows the identification of the time periods during which the utility is a part of an RTO that has established a transparent wholesale market. The transparency mechanism employed by the various RTOs, the posting of wholesale prices on a public website, are nearly identical, so the effect of this mechanism is treated as homogenous across RTOs. Total sources and disposition of energy on the form is disaggregated into several categories that are important for this study. Data includes the annual generation for each utility, net of the plant's own use (reported as net generation), and purchases from the wholesale market (reported as purchases). Together, these accounts are aggregated as total electricity sources for the utility. The total sources of electricity in a given year must always equal the total disposition of electricity, which is disaggregated into sales to ultimate consumers (retail sales), sales for resale (wholesale sales), and electricity losses (losses due to the transmission or distribution of electricity).

The data set consists of over 64,000 data points, each representing the response of one electric utility to the EIA 861 survey for one year from 1990 through 2009. This data set is an unbalanced panel, with roughly 3000 to 4000 utilities responding in any given year. However, these utilities enter and exit the sample in a non-random fashion, and the inclusion of all utilities in the sample can lead to selection bias (Heckman 1979). Therefore, this analysis employs a balanced panel, only those utilities which have submitted data over the entire 20 year data collection period.

The questions of whether utilities purchase or sell more electricity in the wholesale markets, in the presence of an RTO, will be addressed separately. Initially, only utilities with positive sales to ultimate consumers, that is, utilities which serve retail electric load are considered. This is designated the initial purchase sample. Utilities that do not themselves

generate electricity in any year of the sample are excluded from this sample. These utilities are likely 'all requirements customers'[11] of another utility, and therefore lack the means to serve their electric load, except by purchasing electricity on the wholesale market. The wholesale market interactions of these utilities would therefore be unaffected by the presence of a transparent market because they are restricted to purchasing 100% of their electricity regardless of whether the wholesale market is transparent. The dependent variable for this sample is the fraction of the total sources of energy that is purchased from the wholesale market. The naïve utility Alpha in the initial example would purchase none of its energy requirements in the wholesale market, and its participation in the market may be limited by the coordination costs. As these coordination costs change, the utility may find it beneficial to participate in the market. Initially, the utility may only participate in the market when necessary (i.e. when it has insufficient generation to meet its needs, perhaps due to unit outages), and the percentage of its energy that it purchases in the wholesale market may be very low. However, as coordination costs evolve, the utility may also look for economic opportunities to displace its own generation with market purchases, thus increasing the percentage of its requirements that it purchases. In this manner, the dependent variable might change for each utility over time with changes in coordination costs. Participation could also be measured by the volume of wholesale purchases, but this would be expected to increase as the electricity requirements of the utility grow. Normalizing these purchases by the total sources of electricity removes this potential bias.

Similarly, the initial sales sample includes all utilities with positive net electricity generation in a given year, with the exception of any utility that sold all of that generation in the wholesale market over the entire time period in the study. These utilities are likely wholesale

[11] These are utilities that serve retail electricity customers but purchase all of the electricity required to serve them on the wholesale market.

generators, and the presence of a transparent wholesale market will have no effect on whether they participate in the wholesale market. The dependent variable in this case is the fraction of total disposition of energy that is sold on the wholesale market.

Broader criteria may be used to derive the samples, however. Recall that the initial purchase sample excluded any utility that did not generate electricity in any year during the sample period. However, a transparent wholesale marketplace might afford utilities that do not generate electricity the opportunity to purchase electricity not needed to serve retail load, and then resell that electricity to another retail provider. Utilities that exploit this opportunity in the wholesale market are excluded from the initial sample, but the presence of a transparent wholesale market may still influence their behavior. Therefore, the second purchase sample includes all utilities in the initial purchase sample, and all utilities that reported sales for resale during the sample period. This sample is much larger, and affords the opportunity to use the majority of the data points. Similarly, the second sales sample encompasses generating utilities that serve ultimate consumers during some period during the sample. Unlike the broader purchase criteria, this does not lead to a sizable increase in the portion of the sample used.

Model

The model to be estimated is the dependent variable (*DV*), which is either the fraction of the total sources of energy that comes from the wholesale market (for the Purchase regressions), or the fraction of total disposition of energy that is sold on the wholesale market (for the Sale regressions).

$$DV_{it} = \alpha_i + \beta_0 MktUtils_t + \beta_1 Time + \beta_2 ISO\_Whl_{it} + \beta_3 ISOYrs_{it} + \beta_4 ISOYrs_{it}^2 + \beta_5 SumPk + \beta_6 Federal_i + \beta_7 Muni_i + \beta_8 IOU_i + \beta_9 SumPkxISO + \beta_{10} MunixISO + \beta_{11} IOUxISO + \beta_{12} SumPkxISOYrs + \beta_{13} SumPkxISOYrs^2 + \beta_{14} MunixISOYrs + \beta_{15} IOUxISOYrs + \beta_{16} IOUxISOYrs^2 + \varepsilon_{it} \quad (3\text{-}1)$$

$$\varepsilon_{it} = \rho \varepsilon_{it-1} + \eta_{it}$$

Changes in the dependent variable are explained by a utility-specific fixed effect, the number of utilities that exist in the 48 contiguous United States in the given year (*MktUtils*), a linear time trend (*Time*), an indicator variable equal to 1 if the utility is a member of an RTO that operates a transparent wholesale market in that year (*ISO_Whl*), the number of years that the utility has been in a transparent wholesale market (*ISOYrs*), the size of the utility measured by its summer peak demand (*SumPk*), and indicator variables equal to 1 depending on the ownership of the utility (*Federal* if it is a federal power project, *Muni* if a municipally-owned utility, and *IOU* if a privately-owned utility). Our variables of interest include the *ISO_Whl* and *ISOYrs* variables, as well as the interaction between these variables and the size and ownership variables. Finally, the error terms for each utility were found to exhibit first order serial correlation, and are thus modeled as AR(1) processes. Descriptive statistics for the purchase samples are given in Table 3-1, and the sales samples in Table 3-2.

Table 3-1. Mean and standard deviation of purchase sample

	All	Purch1	Purch2
Purchase%	0.9297	0.8335	0.9419
	0.2136	0.2942	0.1911
MktUtils	3230.8	3217.8	3217.8
	213.4	190.7	190.7
ISO_Whl	0.1458	0.1623	0.1436
	0.3560	0.3688	0.3507
ISOYrs	0.6127	0.7317	0.6061
	1.7849	2.0041	1.7818
SumPk	281.16	634.86	266.04
	2765.44	2491.64	2821.21
Federal	0.0022	0.0048	0.0020
	0.0471	0.0694	0.0453
Muni	0.5873	0.7299	0.6367
	0.4923	0.4440	0.4809
IOU	0.0612	0.1339	0.0528
	0.2397	0.3406	0.2237
N	61370	19405	55484

Table 3-2. Mean and standard deviation of sales sample

	All	Sales1	Sales2
Sales%	0.1567	0.2284	0.2583
	0.3239	0.3452	0.3697
MktUtils	3277.0	3217.8	3217.8
	265.9	190.7	190.7
ISO_Whl	0.2231	0.1480	0.1510
	0.4164	0.3551	0.3581
ISOYrs	0.9561	0.6359	0.6551
	2.1612	1.8277	1.8607
SumPk	463.74	1081.18	1056.29
	2016.93	3027.79	2982.65
Federal	0.0045	0.0134	0.0129
	0.0671	0.1148	0.1127
Muni	0.5701	0.6231	0.6061
	0.4951	0.4846	0.4886
IOU	0.0997	0.2066	0.2137
	0.2997	0.4049	0.4099
N	35784	9819	10165

Notable by its absence from the data set is the utility's cost relative to the costs of other utilities in its area. This variable is especially notable because it is the catalyst for the interaction in the hypothetical example of utilities Alpha and Beta. However, hourly wholesale price data is not available for utilities that do not participate in transparent wholesale markets, the control group for this study. In lieu of this data, the effect of cost differentials could be modeled with a variety of annual aggregated regional price differentials, such as mean and maximum differentials. Doing so failed to generate coefficients on these variables that were significant at any reasonable level, and did not affect the magnitude or statistical significance of other variables in the model. Moreover, the relatively high R^2 values in the regressions reported below suggest that the explanatory power of any omitted variables is relatively small.

The treatment effect in the model, whether the utility is a member of an organization that operates a transparent wholesale market, might be seen as endogenous, but it is important to note that membership in an RTO or ISO is mandatory for any utility located in a state that

restructured its electricity market, and that the decision to restructure the market was made by the state legislatures, and not the utility itself. Further, utilities that operate within the control area of a larger utility may find themselves compelled to join an RTO if their control area operator does so. Finally, as argued in Kwoka (2006), price is often cited as the decision to initiate changes in the electricity market, not purely participation in the market itself. However, additional analyses are performed in this paper with a sample free from endogeneity concerns, and the basic results still stand.

The utility specific fixed effect accounts for the fact that utilities serve their load obligations with different combinations of owned generation and purchased power. Due to the long-lived nature of generating assets, this fixed effect will simply reflect the average purchases and sales of the utility over time, and will be relatively stable. The Market Utilities variable is expected to be positive, as the liquidity of the market should increase as more utilities are participating in it. The remaining variables are the variables of interest, although the null hypothesis suggests that the effects of the constraints imposed by the transparent wholesale markets would be less than the effects of the cost reduction of the information regarding electricity availability and price, and that the coefficients on these variables will be positive. A variable to track how long the utility has been involved with a transparent wholesale market is also included, to discern whether the length of time that utilities have been exposed to this market changes the degree to which they participate.

Results

The results of the estimation with the initial sample are given in Table 3-3

Table 3-3. Parameter estimates for initial sample

Variable	% Purchased	% Sold
Constant	0.5532***	0.1572***
	(0.0088)	(0.0034)
MktUtils	1.19e-05***	1.62e-05***
	(2.60e-06)	(2.70e-06)
Time	0.0040***	0.0011**
	(0.0004)	(0.0005)
ISO_Whl	-0.0140	0.0180*
	(0.0159)	(0.0095)
ISOYrs	-3.55e-03	-2.93e-03
	(4.73e-03)	(4.14e-03)
ISOYrs^2	3.07e-04	5.91e-04
	(2.78e-04)	(6.48e-04)
SumPk	-2.72e-06***	-1.04e-06***
	(5.86e-07)	(3.66e-07)
Federal	-3.36e-05	
	(8.24e-02)	
Muni	0.2360***	-0.0035
	(0.0341)	(0.0115)
IOU	0.2181***	0.0431
	(0.0723)	(0.0469)
SumPk x ISO_Whl	5.15e-06**	-2.38e-06
	(2.13e-06)	(1.51e-06)
Muni x ISO_Whl	0.0150	-0.0273***
	(0.0163)	(0.0102)
IOU x ISO_Whl	-0.0016	0.0132
	(0.0211)	(0.0134)
SumPk x ISOYrs	-2.47e-07	-4.72e-07
	(1.06e-06)	(8.79e-07)
SumPk x ISOYrs^2	1.19e-07	4.71e-08
	(1.13e-07)	(9.29e-08)
Muni x ISOYrs	-0.0049	0.0084***
	(0.0039)	(0.0032)
IOU x ISOYrs	0.0461***	0.0043
	(0.0086)	(0.0069)
IOU x ISOYrs^2	-0.0025***	0.0006
	(0.0007)	(0.0006)
N	18425	9295
Number of clusters (utilities)	980	524
R-squared	0.8736	0.9532
Rho	0.6820	0.7784

(Standard errors in parentheses)
(Blanks indicate coefficients omitted due to collinearity)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

The number of utilities in the market has a positive and significant effect on the fraction of wholesale purchases and sales for the utilities, but the magnitude of the effect is not large. The coefficient implies that an additional 1000 utilities, increasing the market size by approximately 25%, would result in an extra 1.2% in purchases or 1.6% in sales. Since the relevant product in the wholesale electricity market is a kWh of electricity delivered to a particular location, the presence of an additional utility in the state of Ohio, say, would likely have little effect on the degree of market participation of a utility near Los Angeles, and this effect is reflected in the magnitude of this coefficient. It appears, from the time trend, that utilities have been purchasing about 0.4% more and selling about 0.1% more of their electricity in the wholesale market every year. The number of years exposed to the wholesale market does not have a statistically significant effect, but does when interaction terms are considered. The coefficient on the size of the utility alone indicates that larger utilities have a tendency to purchase and sell less electricity. However, the magnitude of this effect is very small. For a utility with a peak demand of 1000 MW, for example, slightly smaller than the utility in Knoxville, Tennessee, the effect on purchases would be -0.3% and on sales would be -0.1%. The interaction terms are far more interesting. They indicate that a larger utility sells more in a transparent wholesale market. The same Knoxville-sized utility purchases an additional 5% of its electricity in an ISO. They also indicate that municipally-owned utilities decrease their sales into a transparent wholesale market by approximately 2.7%, but that experience in the market increases sales by 0.8% per year. This may occur if the transactions costs of the market are not fully understood, but more information regarding their magnitude is gained over time[12]. Meanwhile, privately-owned utilities participate in the markets to a much greater degree, increasing their purchases by 4.3% but this participation

[12] For example, on April 25, 2006, FERC ordered MISO to recalculate revenue sufficiency guarantee charges retroactive to May 1, 2005, as a result of the misapplication of their tariff. (115 FERC ¶61,108)

increases at a decreasing rate. The coefficients for the purchase sample imply the relationship shown in Figure 3-1.

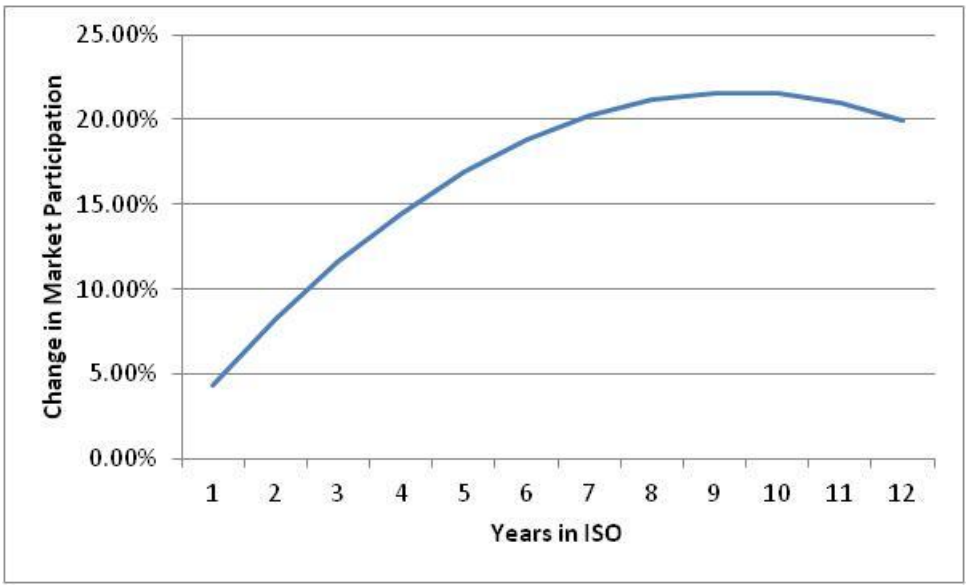


Figure 3-1. Effect of the IOUxISOYrs and IOUxISOYrs2 coefficients on wholesale market purchases of the initial sample

While the magnitude of the coefficients imply that the effect on participation will eventually become negative, it is important to realize that this point, sometime in the 19th year, is beyond the time horizon of the sample. Transparent wholesale markets have only existed in the sample for 12 years, so these coefficients may not reflect the nature of this relationship over a longer period of time. It is clear that, in the time frame of this analysis, experience in the markets increases participation at a decreasing rate. Similarly, the coefficients for privately-owned utilities in the sales sample, and larger utilities in the purchase and sales samples, imply that market participation increases at an increasing rate within the time period of study sample, but this behavior cannot be expected to continue indefinitely.

So, while the participation of municipal utilities in transparent wholesale markets increases gradually in time, larger utilities and privately-owned utilities seem to participate more in a transparent whole market. These broad results are similar in concept to the results of Rose and Joskow (1990) who concluded that larger utilities and privately-owned utilities adopted new gas-fired generating technologies sooner than smaller and municipally-owned utilities. In this instance, the creation of a transparent wholesale electricity market can be seen as the technological innovation being adopted by the utilities. Further, the results for privately-owned utilities are consistent with the results of Fabrizio (2012).

Estimating the regression for the expanded sample changes the coefficients, but does not change the basic results, as shown in Table 3-4. Recall that this expended sample includes utilities that may not own generation themselves, but purchase electricity in excess of the needs of their customers to resell on the wholesale market. The effect of the number of utilities is positive and significant for both samples. The time trend is still positive and significant, but smaller in magnitude. The presence of the market itself increases sales by 2.0%. Again, larger utilities increase participation in the ISO markets, with the sales for a 1000 MW utility increasing almost 5.0%. Municipal utilities in the sample exhibit a similar pattern to the initial sample, with an initial decrease in sales, and a subsequent increase over time. Larger utilities again exhibit a quadratic increase in purchases, to the temporal limit of our sample.

Table 3-4. Parameter estimates for expanded sample

Variable	% Purchased	% Sold
Constant	0.5405***	0.1576***
	(0.0030)	(0.0032)
MktUtils	6.55e-06***	1.72e-05***
	(9.21e-07)	(2.60e-06)
Time	1.83e-03***	1.33e-03***
	(1.48e-04)	(4.69e-04)
ISO_Whl	-2.42e-03	0.0203**
	(3.29e-03)	(0.0090)

Table 3-4. Continued

Variable	% Purchased	% Sold
ISOYrs	-2.92e-03**	-1.16e-03
	(1.27e-03)	(3.92e-03)
ISOYrs^2	1.43e-04	-8.01e-04**
	(1.04e-04)	(3.26e-04)
SumPk	-1.08e-07	-1.03e-06***
	(6.98e-08)	(3.62e-07)
Federal	0.0349	
	(0.0497)	
Muni	0.5546***	5.19e-04
	(0.0146)	(1.01e-03)
IOU	0.1587***	0.1158***
	(0.0222)	(0.0444)
SumPk x ISO_Whl	4.91e-06***	-2.40e-06
	(1.23e-06)	(1.48e-06)
Muni x ISO_Whl	3.15e-03	-0.0299***
	(3.67e-03)	(0.0097)
IOU x ISO_Whl	-0.0127	0.0100
	(0.0084)	(0.0127)
SumPk x ISOYrs	-4.32e-07	-4.67e-07
	(6.11e-07)	(8.58e-07)
SumPk x ISOYrs^2	1.62e-07**	4.56e-08
	(6.46e-08)	(9.02e-08)
Muni x ISOYrs	-0.0011	7.35e-03**
	(0.0010)	(3.01e-03)
IOU x ISOYrs	0.0427***	1.60e-03
	(0.0041)	(6.60e-03)
IOU x ISOYrs^2	-0.0023***	7.21e-04
	(0.0004)	(6.13e-04)
N	52682	9621
Number of clusters (utilities)	2802	544
Rho	0.6907	0.7787
R-squared	0.8839	0.9578

(Standard errors in parentheses)
(Blanks indicate coefficients omitted due to collinearity)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

The pattern for privately-owned utilities is similar as well. The coefficients for market experience imply the relationship in Figure 3-2, but it is still important to consider the temporal

limits of the sample. Once again, the effect on market participation for municipal utilities is small relative to the effect for larger and privately-owned utilities.

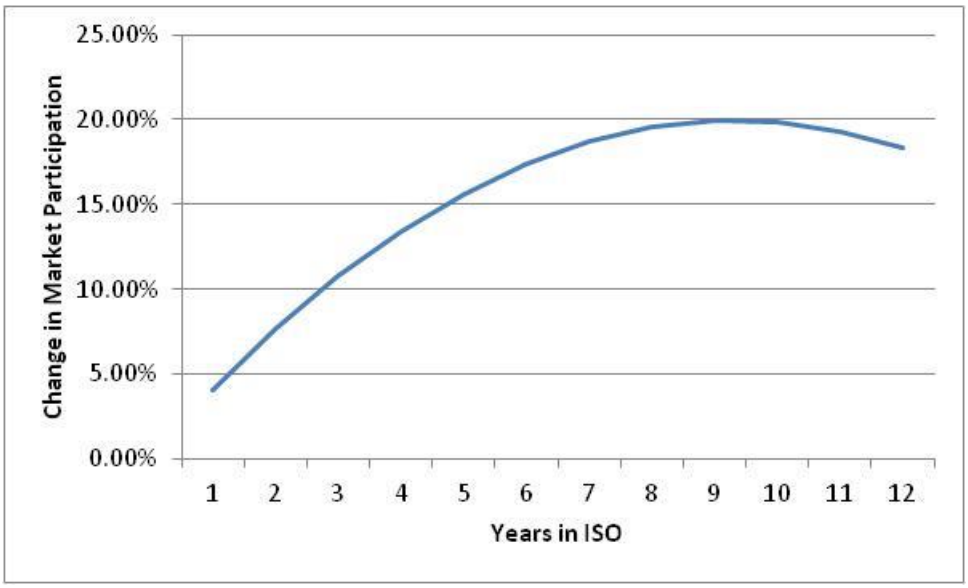


Figure 3-2. Effect of the IOUxISOYrs and IOUxISOYrs2 coefficients on wholesale market purchases of the expanded sample

Relative to the ownership status of the utility, the size of the utility has a smaller effect on the degree of market participation. Figure 3-3 shows the effect of the interaction between the size of the utility and its experience in an ISO. These coefficients are from Table 3-4 and illustrate the change in market purchases for a 1000 MW utility. Note that for the first four years, the effect is nearly zero, but increases thereafter. But even at 12 years of experience, the utility's peak load would have to be 10,000 MW, or larger than the City of Los Angeles, for the magnitude of the size and experience effect to be equivalent to the privately-owned utility experience effect.

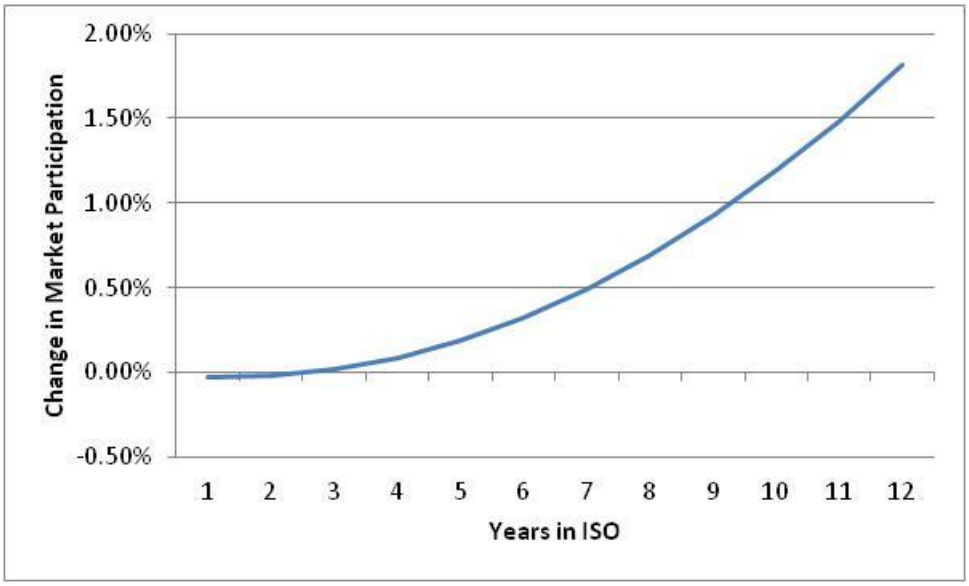


Figure 3-3. Effect of the SumPkxISOYrs and SumPkxISOYrs2 coefficients on wholesale market purchases of a 1000 MW utility in the expanded sample

As discussed earlier, the dependent variable for market participation could be thought of as endogenous. In order to evaluate whether this endogeneity might have an effect on the results, the estimation is repeated using only states that restructured their electricity industry. This restructuring, enabled by FERC and initiated by state legislatures, required utilities to either relinquish their assets, or the control of their assets, to a third party. For the utilities' transmission assets, this third party was the ISO or RTO. Thus, utilities in restructured states that joined RTOs did so not of their own accord, but because they were compelled by the state legislature. As discussed in Kwoka (2006), the motivation for states to restructure was high electricity prices, and not the dependent variable in this analysis, so a sample consisting only of restructured states should be free of these endogeneity concerns. The results of this estimation are shown in Table 3-5.

Table 3-5. Parameter estimates for expanded sample: utilities in states that restructured their electricity industry

Variable	% Purchased	% Sold
Constant	0.6523***	0.1682***
	(0.0062)	(0.0055)
MktUtils	5.79e-06**	3.23e-05**
	(2.38e-06)	(5.88e-06)
Time	4.14e-03***	0.0035**
	(6.29e-04)	(0.0017)
ISO_Whl	-6.18e-04	0.0325**
	(6.57e-03)	(0.0153)
ISOYrs	-5.95e-03**	-6.50e-03
	(2.53e-03)	(7.06e-03)
ISOYrs^2	2.15e-04	-8.29e-04
	(1.79e-04)	(5.60e-04)
SumPk	-4.49e-07	-9.51e-07*
	(4.84e-07)	(4.91e-07)
Muni	0.2813***	-0.0034
	(0.0335)	(0.0275)
IOU	0.1389***	
	(0.0427)	
SumPk x ISO_Whl	8.84e-06***	-5.48e-06*
	(2.08e-06)	(3.03e-06)
Muni x ISO_Whl	2.13e-04	-0.0437**
	(7.32e-03)	(0.0172)
IOU x ISO_Whl	-0.0316**	0.0181
	(0.0142)	(0.0231)
SumPk x ISOYrs	-1.99e-06**	-3.00e-07
	(9.73e-07)	(1.62e-06)
SumPk x ISOYrs^2	2.23e-07**	2.61e-08
	(9.80e-08)	(1.54e-07)
Muni x ISOYrs	-8.24e-04	1.08e-02**
	(1.77e-03)	(5.12e-03)
IOU x ISOYrs	0.0687***	0.0078
	(0.0069)	(0.0120)
IOU x ISOYrs^2	-0.0041***	7.13e-04
	(0.0006)	(1.05e-03)
N	12675	2898
Number of clusters (utilities)	686	173
Rho	0.7467	0.8136
R-squared	0.8525	0.9298

(Standard errors in parentheses)
(Blanks indicate coefficients omitted due to collinearity)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

The coefficients in Table 3-5 differ from those in Table 3-4, but the basic results of the analysis remain. Market participation in the purchase market tends to increase for larger utilities

and privately-owned utilities. Municipal utilities experience an initial drop in level of sales participation, but increase sales with experience. Larger utilities overall tend to sell less, but the amount is small in magnitude. Thus, the potential endogeneity of the dependent variable is not driving the results of the analysis.

Since the results for restructured states are consistent with those for the entire sample, this might beg for the question of whether restructuring is solely responsible for the results. To test whether this is true, the estimation is repeated using the complement of the data set in Table 3-5, just those states that did not restructure their electricity industry. The results of this estimation are shown in Table 3-6.

Table 3-6. Parameter estimates for expanded sample: utilities in states that did not restructure their electricity industry

Variable	% Purchased	% Sold
Constant	0.4463***	0.1822***
	(0.0035)	(0.0031)
MktUtils	5.92e-06**	4.79e-06*
	(9.50e-07)	(2.52e-06)
Time	1.23e-03***	9.70e-04***
	(1.10e-04)	(3.30e-04)
ISO_Whl	-3.22e-03	-1.75e-03
	(3.93e-03)	(1.13e-02)
ISOYrs	-9.88e-04	4.98e-03
	(1.75e-03)	(4.92e-03)
$ISOYrs^2$	-1.99e-04	-5.10e-04
	(2.02e-04)	(4.33e-04)
SumPk	-9.10e-08	-1.06e-06
	(6.40e-08)	(1.02e-06)
Federal	-0.0157	
	(0.0415)	
Muni	0.7452***	-7.81e-04
	(1.41e-02)	(8.96e-03)
IOU	0.0540**	0.1060***
	(0.0257)	(0.0334)
SumPk x ISO_Whl	1.04e-06	7.36e-09
	(1.76e-06)	(1.90e-06)
Muni x ISO_Whl	2.66e-03	-3.36e-03
	(4.34e-03)	(1.20e-02)

Table 3-6. Continued

Variable	% Purchased	% Sold
IOU x ISO_Whl	0.0030	9.40e-03
	(0.0127)	(1.62e-02)
SumPk x ISOYrs	-1.84e-06*	-7.99e-07
	(1.05e-06)	(1.52e-06)
SumPk x ISOYrs^2	5.35e-07***	9.24e-08
	(1.41e-07)	(2.50e-07)
Muni x ISOYrs	6.79e-05	-0.0014
	(1.32e-03)	(0.0040)
IOU x ISOYrs	1.77e-02***	7.79e-03
	(1.06e-02)	(8.24e-03)
IOU x ISOYrs^2	-1.60e-03**	-1.30e-03
	(6.90e-04)	(8.25e-04)
N	39986	6704
Number of clusters (utilities)	2137	390
Rho	0.6092	0.7193
R-squared	0.9201	0.9782

(Standard errors in parentheses)
(Blanks indicate coefficients omitted due to collinearity)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

The observed pattern in the purchase market continues to hold, with larger utilities and privately-owned utilities tending to purchase more. No variables of interest remain statistically significant in the sales sample, suggesting that restructuring may be driving the results in the sales sample. However, the overall results for the purchase sample seem robust to different subsamples.

Finally, to test whether the results are driven by the relationship between municipally-owned utilities and privately-owned utilities, the participation equations can be separately estimated with each subsample. The results of these estimations are shown in Table 3-7 and Table 3-8.

Table 3-7. Parameter estimates for expanded sample: municipal utilities

Variable	% Purchased	% Sold
Constant	0.8858***	0.0260***
	(0.0016)	(0.0025)
MktUtils	1.35e-05***	1.31e-05***
	(1.24e-06)	(3.14e-06)
Time	2.84e-03***	1.35e-03***
	(1.65e-04)	(4.72e-04)
ISO_Whl	-1.25e-03	-4.59e-03
	(2.49e-03)	(4.62e-03)
ISOYrs	-4.74e-03***	2.61e-03
	(1.29e-03)	(2.90e-03)
$ISOYrs^2$	8.47e-05	-4.26e-04
	(1.22e-04)	(3.03e-04)
SumPk	-2.24e-06	1.15e-06
	(4.39e-06)	(3.99e-06)
SumPk x ISO_Whl	2.46e-05**	-6.77e-06
	(1.15e-05)	(1.07e-05)
SumPk x ISOYrs	-1.60e-05**	4.95e-06
	(6.56e-06)	(6.82e-06)
$SumPk\ x\ ISOYrs^2$	2.29e-06***	-4.78e-07
	(7.39e-07)	(7.26e-07)
N	33471	5709
Number of clusters (utilities)	1785	338
Rho	0.6304	0.7803
R-squared	0.8567	0.9293

(Standard errors in parentheses)
(Blanks indicate coefficients omitted due to collinearity)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

Table 3-8. Parameter estimates for expanded sample: investor owned utilities

Variable	% Purchased	% Sold
Constant	0.3397***	0.1879***
	(0.0075)	(0.0067)
MktUtils	4.05e-05***	2.86e-05***
	(7.31e-06)	(6.71e-06)
Time	7.60e-03***	5.50e-04
	(2.52e-03)	(1.68e-03)
ISO_Whl	-0.0219	0.0346**
	(0.0156)	(0.0167)

Table 3-8. Continued

Variable	% Purchased	% Sold
ISOYrs	0.0235**	0.0045
	(0.0092)	(0.0095)
ISOYrs^2	-1.48e-03*	-3.48e-04
	(7.91e-04)	(8.65e-04)
SumPk	-5.14e-06***	-6.75e-07
	(1.83e-06)	(1.75e-06)
SumPk x ISO_Whl	6.20e-06**	-3.71e-06
	(2.80e-06)	(3.02e-06)
SumPk x ISOYrs	4.60e-07	-1.18e-06
	(1.43e-06)	(1.64e-06)
SumPk x ISOYrs^2	-5.59e-09	1.07e-07
	(1.49e-07)	(1.60e-07)
N	2757	2131
Number of clusters (utilities)	151	117
Rho	0.8263	0.7881
R-squared	0.8153	0.8454

(Standard errors in parentheses)
(Blanks indicate coefficients omitted due to collinearity)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

The basic results still hold when the individual ownership samples are considered. Municipal utilities show a decrease in purchases in ISOs, but this effect is mitigated for larger utilities. For the privately-owned utilities, experience in ISOs increases purchase market participation at a decreasing rate, consistent with the earlier results. And once again, participation in the purchase market increases with the size of the utility. In the sales sample, privately-owned utilities in ISOs tend to sell about 3% more. So while the coefficients change in these subsamples, the basic results of the analysis remain the same: municipal utilities tend to participate less in the ISOs, while privately-owned and larger utilities tend to participate more, and these results are robust to different samples.

Conclusions

It is clear that RTOs and ISOs can provide opportunities in the electricity market that might not otherwise exist. One such opportunity is the facilitation of the transparent wholesale electricity market. Transparent wholesale markets can reduce coordination costs that limit the participation of utilities in the marketplace, and thus limit opportunities that might arise with that participation. However, these formal markets also impose costs that may discourage participation in the wholesale market.

This paper estimates the determinants of market participation, and shows that the presence of a transparent wholesale marketplace for electricity has the effect of increasing participation in the wholesale market, but that this participation does not occur symmetrically across all types of electric utilities. Greater participation is induced in privately-owned and larger utilities, reflecting both the results of Rose and Joskow, who found that privately-owned and larger electric utilities are more willing to adopt technological innovations in the electricity industry, and Fabrizio, who found that privately-owned utilities in ISOs tend to meet more of their growing electricity needs by purchasing electricity.

These results have important implications for public policy aimed at increasing transparency in wholesale electricity markets, and the organizations that facilitate it, as the opportunities afforded by this policy may not be uniformly distributed across all market participants.

CHAPTER 4
CHALLENGES IN QUANTIFYING OPTIMAL CO2 EMISSIONS POLICY: THE CASE OF ELECTRICITY GENERATION IN FLORIDA

Introduction

Questions regarding the economic impact of carbon dioxide (CO_2) emissions continue to accompany any discussion regarding the imposition of emission limits. However, most of these discussions focus on only one side of the relationship between CO_2 prices and emissions levels. That is, they attempt to quantify the resulting CO_2 price implied by an exogenous level of emissions, or the emissions level that would result from a given emissions price. Studies that take either price or emissions level as exogenous may not offer insight into the question of the optimal level of abatement[1], by ignoring the interaction between them. This paper, considers the effects of a range of CO_2 prices, thereby informing an analysis of the average cost curves for emissions abatement, which provides insight into the unusual behavior of the marginal costs of abatement. Such insight is necessary in any discussion of optimal levels of emissions abatement.

In July of 2007, Florida Governor Charlie Crist hosted the historic "Serve to Preserve: A Florida Summit on Global Climate Change," in Miami. This summit brought business, government, science, and stakeholder leaders together to discuss the effects of climate change on Florida and the nation. On the second day of the summit, July 13, the Governor signed three Executive Orders to shape Florida's climate policy. Order 07-126 mandated a 10% reduction of greenhouse gas emissions from state government by 2012, 25% by 2017, and 40% by 2025. Order 07-127 mandated a reduction of greenhouse gas emissions from the state of Florida to 2000 levels by 2017, 1990 levels by 2025, and 20% of 1990 levels by 2050. Finally, Order 07-128 established the Florida Governor's Action Team on Energy and Climate Change and

[1] Targeted levels of emission reduction are frequently alliterative, such as 50% by 2050.

charged the team with the development of a comprehensive Energy and Climate Change Action Plan.

On June 25, 2008, Florida House Bill 7135 was signed into law by Governor Crist, creating Florida Statute 403.44 which states: "The Legislature finds it is in the best interest of the state to document, to the greatest extent practicable, greenhouse gas emissions and to pursue a market-based emissions abatement program, such as cap and trade, to address greenhouse gas emissions reductions." The initial focus of the state government is to place a cap on the amount of carbon dioxide emitted by the electric power generation sector.

In cooperation with the State of Florida's Department of Environmental Protection, the Florida legislature commissioned a study of the economic impacts on the state of such a program. This paper utilizes a version of the model[2] constructed for that study (Kury and Harrington 2010) to simulate the dispatch of electric generating units in the state of Florida over a range of CO_2 prices. The analysis concludes that the marginal cost of abatement curve may not be well-behaved, implying several points where the marginal costs of abatement are equal to the marginal benefits. This behavior can complicate the question of an optimal level of CO_2 abatement.

The remainder of this paper is organized as follows: Section II provides a review of the literature on the economic effects of CO_2 emissions, Section III describes the model of economic dispatch, Section IV describes the data sources utilized, Section V discusses the mechanics of the simulation, Section VI discusses the model results, and Section VII provides some concluding remarks.

[2] The inputs to the model have been updated.

Literature Review

Nordhaus (1980) is credited as being the first to derive optimal levels of CO_2 emissions, in a model of the CO_2 cycle and CO_2 abatement. He further discussed a model of the effects of CO_2 buildup in the environment and the intertemporal choice of consumption paths, and ended with suggestions regarding how to compare control strategies. He also identified three empirical issues with policy implementation: the problem that CO_2 emission is an externality across space and time, whether to control CO_2 emissions with quantities or prices, and the effects of uncertainty regarding the costs and benefits of CO_2 abatement. Further theoretical research has explored aspects of the Nordhaus model, such as Goulder and Mathai (2000), who characterized optimal carbon taxes and CO_2 abatement under different channels for knowledge accumulation, under cost-effectiveness and benefit cost criterion.

The bulk of the literature consists of *ex-ante* studies of proposed levels of emissions abatement. In the United States, the Congressional Budget Office (CBO), Environmental Protection Agency (EPA), and the Department of Energy's Energy Information Administration (EIA) have all studied the effects of legislation proposed in the House of Representatives and the Senate. These analyses typically treat the levels of emissions proposed in the bills as exogenous, and attempt to determine their economic impact. For example the EIA analysis of the American Power Act of 2010 concluded that CO_2 emissions prices in the Base Case would reach $32 per ton in 2020 and $66 per ton in 2035. This analysis is limited in its ability to offer insight into policy alternatives, however.

Studies on the regional economic impact of CO_2 pricing on the market for electric generation have been performed for the ERCOT region in Texas[3], as well as the PJM region in

[3] http://www.ercot.com/content/news/presentations/2009/Carbon_Study_Report.pdf

the Northeastern United States[4]. Examining the conclusion for those two studies shows how the relative carbon intensity of the electric generation fleet can have a marked impact on the economic effects of CO_2 pricing. Pennsylvania relies on more coal-fired generation, and therefore the impact of a $1 increase in carbon prices results in a $0.70/MWh increase in wholesale electricity prices. Texas, which relies more on natural gas sees its wholesale prices increased approximately $0.50/MWh with a $1 increase in CO_2 prices. Similar analyses have been conducted for the European market. Honkatukia et. al (2006) studied the degree to which allowance prices in the European Union Emissions Trading System for CO_2 get passed through to the wholesale prices in Finland, and concluded that 75% to 95% of the price change is passed through to the spot price.

A comparative analysis was conducted by Newcomer et al. (2008) who modeled the short run effects of a range of CO_2 prices on the price of electricity and level of carbon dioxide emissions in three regions of the United States, but the determination of an optimal level of abatement was beyond the scope of their work.

The literature on the social costs of CO_2 emissions presents a diverse range. The Contribution of Working Group II to the Fourth Assessment Report to the Intergovernmental Panel on Climate Change (2007) cited the results of a survey of 100 estimates of the social cost of CO_2 that reported a range from -$3 per ton to $95 per ton. This survey was taken from Tol (2005), which reported a mean of $43 per ton (in 2005$) of carbon with a standard deviation of $83 per ton of carbon[5] in the peer-reviewed studies. In its modeling, the Interagency Working Group on the Social Cost of Carbon, United States Government (2010), uses values from $5.70

[4] http://www.pjm.com/documents/~/media/documents/reports/20090127-carbon-emissions-whitepaper.ashx

[5] These figures convert to $11.62 and $22.43 per ton of CO_2, respectively.

to \$72.80 (in 2007\$) for the social cost of CO_2 in 2015, and \$15.70 to \$136.20 for 2050. Anthoff and Tol (2013) analyze the factors that affect the uncertainty in the social cost of carbon and find that the influence of parameters changes depending on the time scale of the analysis or the region considered. They also find that some parameters are more certain than others. Ackerman and Stanton (2012) demonstrate that with high climate sensitivity, high climate damage, and a low discount rate, the social cost of CO_2 could be almost \$900 per ton in 2010.

Model of Economic Dispatch

The problem of least-cost economic dispatch of a group of *n* electric generating units is to minimize the aggregate costs required to provide the amount of electricity demanded by end-users in each hour. The costs to produce this electricity will be driven by the type of generating unit, its thermal efficiency[6], the variable costs required to operate and maintain the unit, and the price of its fuel. For each hour, the problem can be stated:

$$\min_G \sum_{i=1}^{n} G_i \{[(CO2_i * Emit\$) + Fuel\$_i] * HeatRate_i + O\&M\$_i\} \qquad (4\text{-}1)$$

subject to the constraints:

$$\sum G_i \geq L$$

$$G_i \leq C_i \; \forall i$$

where:

G_i	MWh generated by the *i*th generating unit
C_i	Maximum hourly generating capacity in MWh of the *i*th generating unit.
L	Electricity demand by consumers in MWh
$CO2_i$	Tons of CO_2 emitted per MMBtu of fuel consumed by the *i*th generating unit

[6] The thermal efficiency of a power plant is the rate at which it converts units of fuel to a given unit of electricity. This is typically called the heat rate of a power plant, and all else equal, a lower heat rate is preferred to a higher one.

Emit$	Emissions cost per ton of CO_2
$Fuel\$_i$	Cost of fuel per MMBtu consumed by the *i*th generating unit
$HeatRate_i$	Heat rate of the *i*th generating unit in MMBtu of fuel required to produce one MWh of electricity
$O\&M\$_i$	Hourly operation and maintenance expenses of the *i*th generating unit in $/MWh

Without a price for emitting CO_2, the value of *Emit$* is zero and the amount of CO_2 emitted by that generating unit does not enter the dispatch equation. With a positive value for *Emit$*, the total cost of emissions is driven by the operating efficiency of the generating unit and by the type of fuel utilized, as some generating fuels emit relatively more carbon dioxide when burned. Such fuels, which include coal and petroleum coke, are often referred to as "dirty" fuels. Fuels that emit relatively less carbon dioxide when burned, such as natural gas, are referred to as "clean" fuels. Therefore, the price of emissions may necessitate the switch from a dirtier generating fuel to a cleaner one by an individual generator capable of burning more than one type of fuel, or may lead to a generator that burns a dirtier fuel being replaced by a generator that burns a cleaner fuel.

The strategies to reduce emissions from the electric generation sector are limited in the short run. Generators can adjust the types of fuels that they use, known as fuel-switching, or reduce the amount of electricity that they produce. In the long run, the generator's options expand to strategies such as improving the heat rate of existing power plants (thus reducing fuel consumption), construction of new power plants that produce electricity while emitting less (or no) carbon dioxide, or developing and exploiting technologies that captures a portion of the carbon dioxide emitted. The model utilized in this paper allows for both short run and long run strategies.

The determination of the optimum hourly unit dispatch is conducted in two stages. First, the hourly operating cost is minimized for each available generating unit. For units with the capability to burn different fuels, the cost and emissions rate of each fuel are considered and the least-cost alternative is selected. Second, all of the generating units are ordered from lowest cost to highest, and the units with the lowest hourly costs are dispatched until the hourly electric loads are met.

Data Sources

Data on the hourly marginal costs for individual generating units is considered proprietary, so these costs must be estimated. Data for individual generating units, such as summer and winter generating capacity, the type of generating unit, and fuel sources, are available from the EIA Form 860 (Annual Electric Generator Report) and Form 861 (Annual Electric Power Industry Database) databases. Data on generating unit operating efficiency, such as heat rate, are available from EIA Form 423 (Monthly Cost and Quality of Fuels for Electric Plants Data) filings. The heat rate data utilized in this simulation represents the annual average heat rate for each generating unit. Some unit level operating data, such as variable operating and maintenance expenses, are available from utility responses to the Form 1 (Annual Report of Major Electric Utility) required by the Federal Energy Regulatory Commission (FERC). Other operating data is derived from industry averages published by the EIA for use in its Annual Energy Outlook. Unit-specific operating and contract data[7] as well as long term load forecasts, are available from the Regional Load and Resource Plan published by the Florida Reliability Coordinating Council. Actual hourly loads are available from utility responses on Form 714 (Annual Electric Control and Planning Area Report) to the FERC. Data for planned generating

[7] Contract data includes power purchased from other states under long term contracts. As a result, the costs associated with these contracts are sunk, and their marginal cost of dispatch is zero.

units are available from the FRCC Regional Load and Resource Plan. Projected fuel prices and levelized costs of new generation are taken from the 2013 Annual Energy Outlook published by the EIA.

Model Operation

Within each month of a given run, the model first determines the order in which the generating units will be dispatched to meet electric load, often called the generation stack, and then dispatches the generation stack against the monthly load shape on an hourly basis, using Equation 4-1.

When dispatching each unit, the model discounts each unit's production capacity by the unit's availability factor. This availability factor reflects distinct operating characteristics of different types of generating units. Electrical generation for different types of units may or may not be controlled by the operator of the unit. For a unit that burns fossil fuels, if the power plant is running and has fuel available, it will generate electricity. These types of units are also called dispatchable units. For a unit that relies on the sun or the wind to generate electricity, however, that power plant will not produce electricity if the sun is not shining or the wind is not blowing. These types of units are called nondispatchable units.

For nondispatchable units, the availability factor reflects the amount of time that the sun is shining or the wind is blowing. For dispatchable units, this availability factor reflects the times when the unit is available to generate. This methodology, often called a "derate" methodology, accounts for the unit being unavailable due to either a planned or unplanned outage. Ideally, two factors would be used to reflect unit availability. The first would reflect planned unit outages, most commonly for routine maintenance. The second factor would reflect unplanned, or forced, outages; the instances where a unit breaks down unexpectedly. However, individual unit outage

schedules are proprietary and dynamic. To ameliorate these modeling limitations, this availability factor is employed.

The long run strategies employed by the model consider the decisions to build new power plants. The model can either be allowed to build new generating units only when they are necessary to serve electric load, or might be allowed to build new units opportunistically, that is, when the wholesale price of electricity is sufficient to allow the new units to earn a profit. The former approach may not induce generation sufficient to reach more aggressive emission reduction targets, as the composition of the generation fleet is more static, while the latter approach may lead to the problem of stranded investment. Because the construction of new generating units in Florida is regulated through a determination of need proceeding at the state Public Service Commission[8], the former approach has been modeled in this analysis. The opportunistic approach was also modeled, but yielded similar results. Changes in the outlook for natural gas prices limited the emissions reductions that could be achieved even with the opportunistic approach, however. In Kury and Harrington (2010), a carbon price of $90 per ton was sufficient to induce a change in construction to zero-emitting technologies (nuclear and biomass), while the latest prices for natural gas and generating technologies now require a carbon price of $135 per ton to induce the same behavior.

Model Output

During its execution, the model tracks the electricity production for each unit, as well as the units of fuel burned, the total dispatch costs, and the carbon emissions. These output variables are be aggregated by utility, type of plant, fuel type, and plant vintage.

[8] Florida Statutes 403.519

The aggregate model output consists of matched sets of emissions prices, emissions levels, and the volume of each generating fuel burned for each model year. Therefore, each level of emissions in a particular year implies a price of emissions and a fuel mix, and vice versa. In that manner, the model determines the price of emissions and mixture of generating fuels that correspond to each level of carbon dioxide emissions, for each compliance year in the analysis. Further, it also computes the effects of different levels of emissions (and the resulting emissions prices) to allow the characterization of the marginal effects of the emissions policy.The model was run for the years 2012-2025, varying the CO_2 price from $0 to $100 per ton, and the change in several output variables is presented. The first variable is the change associated with the real incremental cost component of electricity production, shown in Figure 4-1.

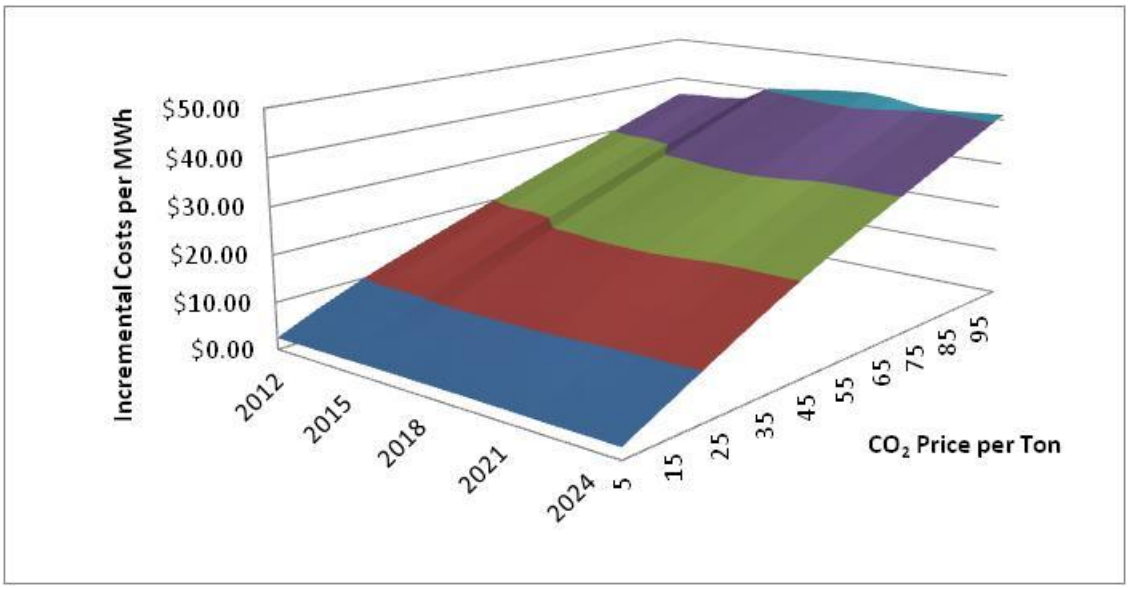


Figure 4-1. Real ($2010) incremental cost of electricity by year and emissions price

While the relationship between emissions prices and incremental cost does change slightly as we look further into the future, the relationship between emissions prices and

incremental cost is fairly stable, as a $1 increase in emissions prices tends to raise the price of electricity in Florida by approximately 50¢ per MWh, or about $6 per year for a family that uses 1000 kWh per month. This effect drops to about 40¢ per MWh as emissions prices increase to $100 per ton. The magnitude of the effect of CO_2 prices on incremental cost reflects the relative carbon intensity of the generating units utilized to produce electricity, so a decrease in the effects of an emissions price as the emissions per MWh of electricity decreases is expected.

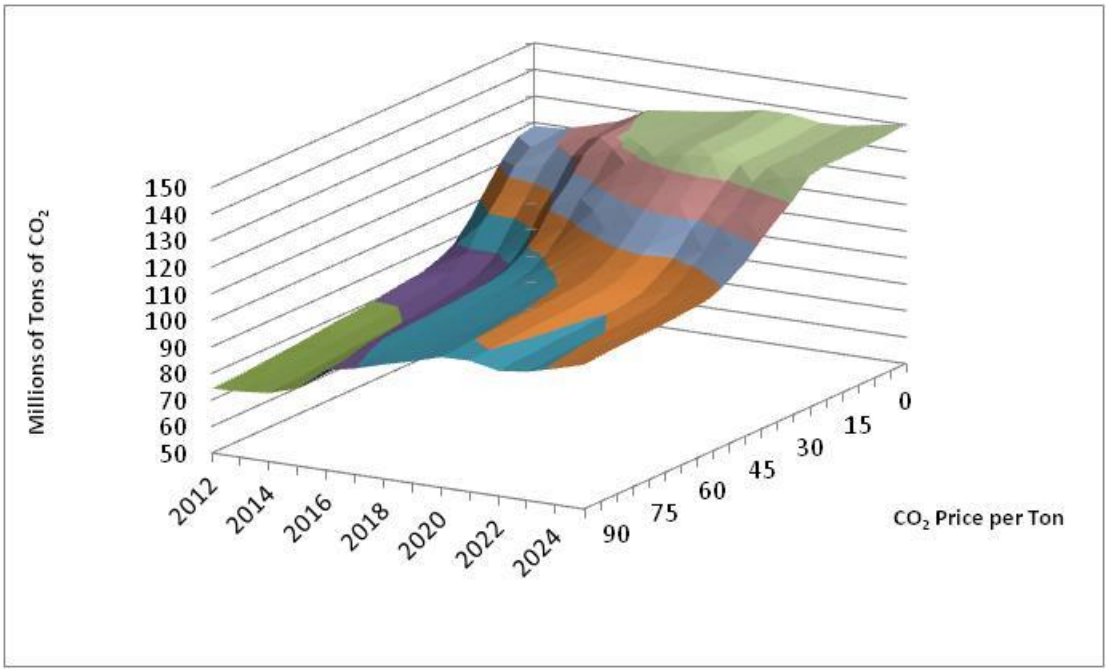


Figure 4-2. Emissions by year and emissions price

Figure 4-2 illustrates the effects of carbon dioxide emissions prices on the emissions of the electric generating sector. Emissions levels are initially reduced 2-3% under relatively low emissions prices. This is primarily due to the displacement of petroleum coke and inefficient coal generators as a source of electricity in Florida. However, emissions levels then reach a plateau, whose magnitude varies with the year, during which increasing the price of emissions has relatively little effect on overall emissions levels. Once emissions prices exceed a critical value,

however, a rapid decline in emissions levels occurs. This decline in emissions occurs at $15 per ton in the short run, as coal-fired generation is quickly displaced by natural gas. The 'flat spots' in the surface, however, are cause for concern for policymakers. These areas are regions in which costs are increasing for consumers[9], in the form of higherrealized costs, but with little corresponding decrease in emissions. Consumers are thus paying higher costs without any concurrent benefit.

The results shown in Figures 4-1 and 4-2 can be consolidated to construct the average cost curves for emissions abatement in a given year. Figure 4-3 shows these average cost curves for selected years in the simulation.

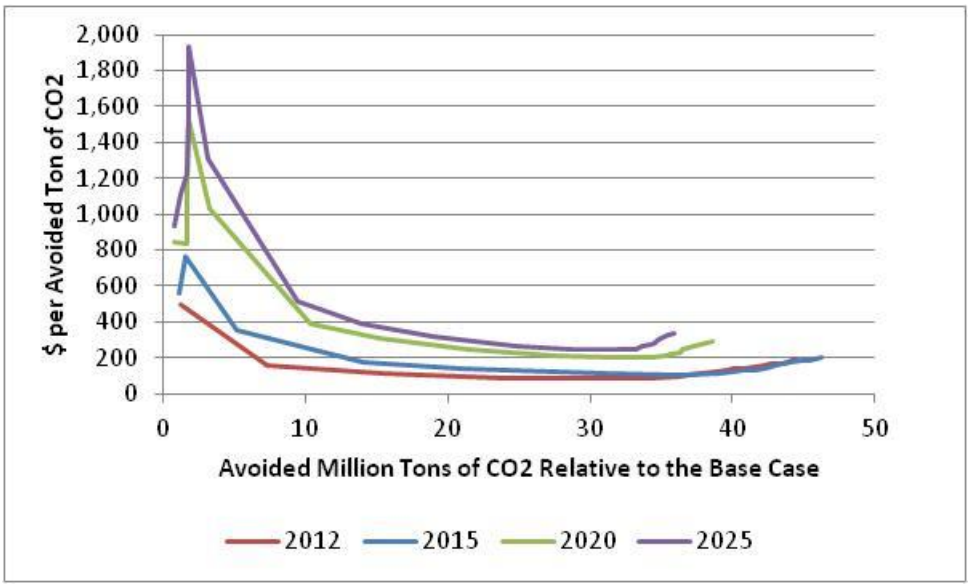


Figure 4-3. Average cost of abatement curves

While the marginal cost of abatement cannot be observed from a discrete model, the shape of the marginal cost curve can be inferred from the behavior of these average cost curves.

[9] As seen in Figure 4-1.

The marginal cost curves for the years 2015, 2020, and 2025 clearly cross the average cost curve multiple times. Therefore, the marginal benefits curve for emission abatement, even if it is itself well-behaved, may intersect the marginal cost curve at more than one level of emissions abatement. To illustrate this phenomenon, the average and incremental costs of abatement for 2015 are shown in Figure 4-4.

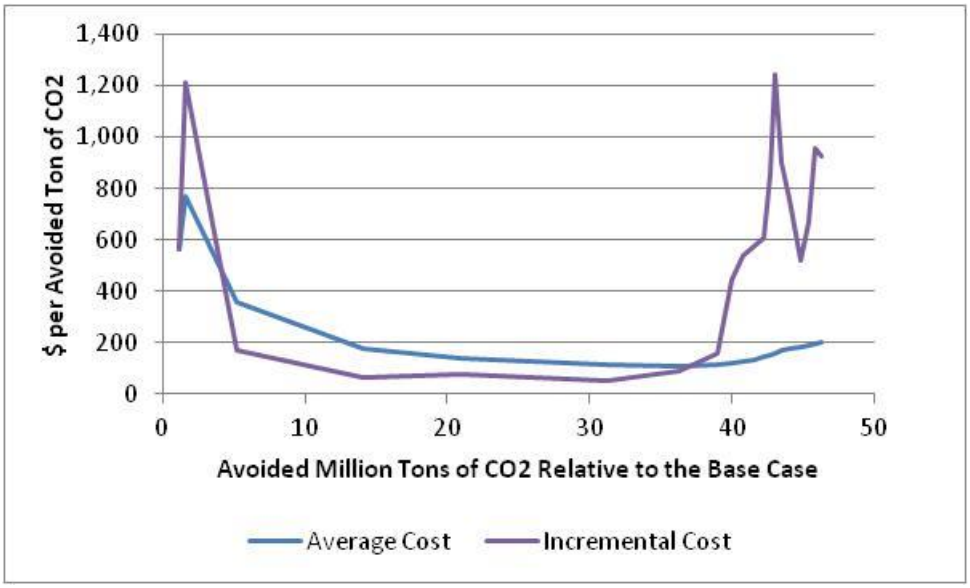


Figure 4-4. Average and incremental cost of abatement curves for 2015

The incremental cost curve for 2015 is clearly not well behaved, sloping upward over several levels of abatement. There is considerable uncertainty surrounding the social cost of CO_2 abatement. If a CO_2 tax of $700 per ton is established, a value at the upper range of the social cost of CO_2 established in the literature, the tax would be equal to the incremental cost of abatement at approximately 1 million, 42 million, and 45 million tons of avoided CO_2. This phenomenon is illustrated in Figure 4-5.

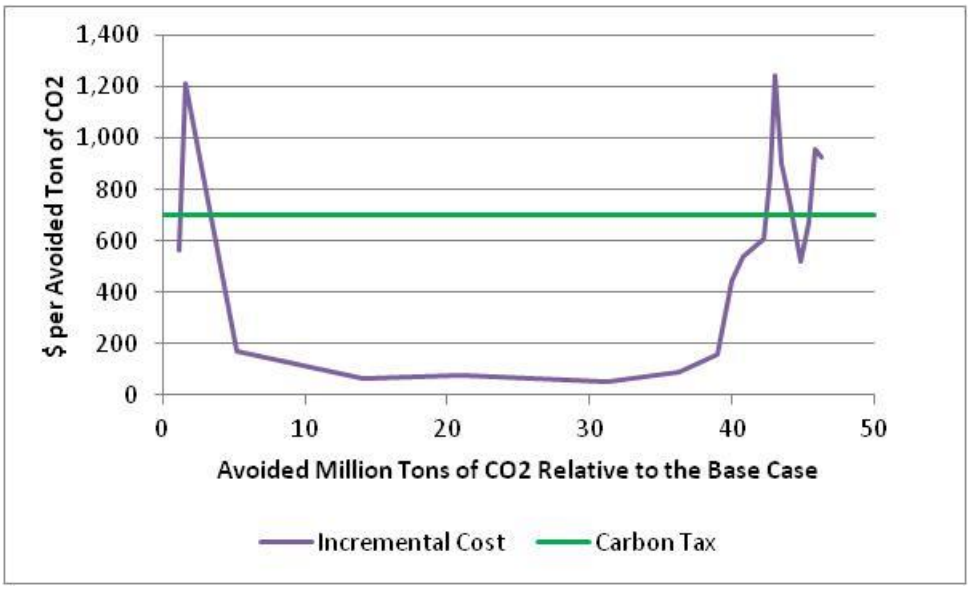


Figure 4-5. Multiple abatement equilibria at a carbon tax of $700

If the tax were equal to $70 per ton, a level within the range of the social cost of CO_2 established by the Interagency Working Group of the United States Government (2010), it would be equal to the incremental cost of abatement at approximately 18 million and 34 million tons of avoided CO_2. This is illustrated in Figure 4-6.

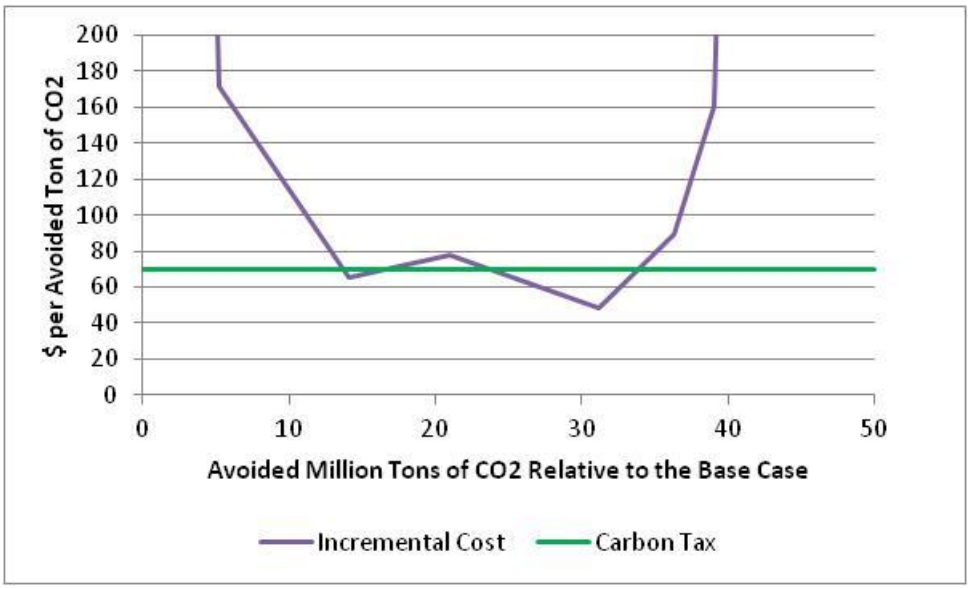


Figure 4-6. Multiple abatement equilibria at a carbon tax of $70

The challenge for policymakers is that when the optimal level of CO_2 abatement is considered, using the criteria of equating marginal costs with marginal benefits, there may not be a single optimum level. Therefore, even if global leaders were to agree on the marginal costs and marginal benefits of CO_2 abatement, an accomplishment that is likely difficult to achieve, there is still the potential to disagree on the optimum level. This would make it difficult to agree on the level of an emissions cap, if that method of regulation is implemented. Further, if emissions control through a carbon tax is considered, it may not result in the desired level of emissions abatement. Therefore, if a specific level of CO_2 abatement is desired by policy makers, the implementation of an emissions cap is the only reliable way to achieve it.

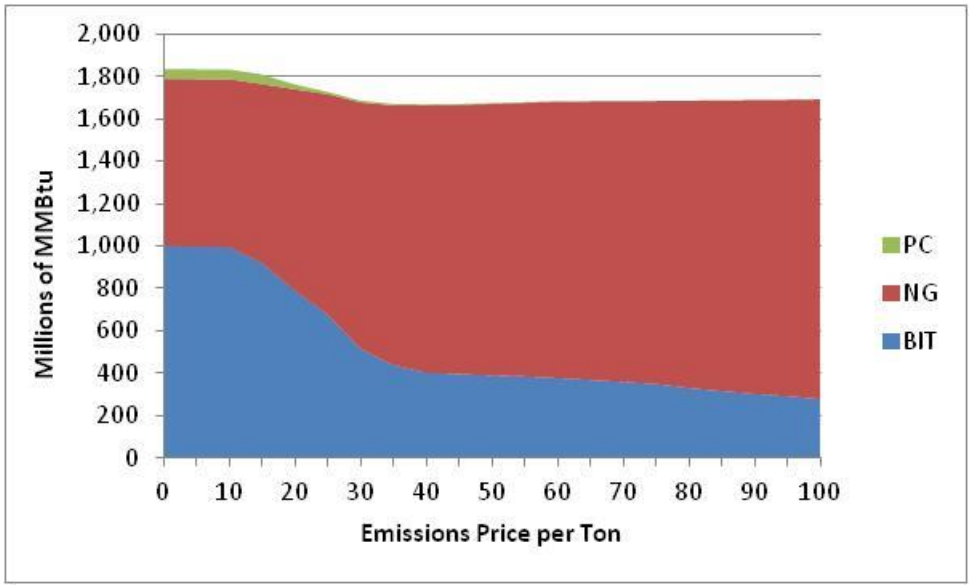


Figure 4-7. Fuel consumption in 2013

Figure 4-7 illustrates the amount of coal (BIT), natural gas (NG), and petroleum coke (PC) burned during the simulation of 2013. These results provide insight into the shape of the emissions surface. Initial reductions in emissions levels occur as petroleum coke and inefficient coal plants, relatively dirty sources of electricity, are displaced. Once the petroleum coke has been fully displaced, further increases in emissions prices eliminate half of the remaining coal consumption and emissions levels decrease rapidly. Once an CO_2 price of $30 per ton is reached, the displacement of the remaining coal fired capacity continues, but at a much lower rate. At CO_2 prices of $70 per ton, for example, the initial consumption of coal has been reduced by 60%.

Conclusions

It is easy to find discussions of government-imposed carbon dioxide abatement targets and the emissions prices that result from these targets, but the literature on discussions of policy alternatives or the establishment of optimal emissions abatement is not well-developed. Since emissions abatement carries a cost to the consumer, however, it is important to ensure that those

costs are commensuarate with the benefits that consumers are receiving from this abatement policy.

This paper presents the results of an analysis of the units used to generate electricity in Florida and the marginal effects of carbon prices on their dispatch. Using the operating characteristics of Florida's generating units, and a least-cost economic dispatch model, this paper analyzes the effects that various emissions prices (and their concurrent emissions levels) have on Florida's level of carbon dioxide emissions and the amounts of fuel consumed for electric generation. We find that at relatively low emissions prices emissions levels decrease as fuel sources such as petroleum coke and coal burned in less efficient plants are displaced. Once this initial reduction has been achieved, further increases in carbon prices may do little to decrease emissions until a "critical point" has been achieved, and most coal generation can be displaced by natural gas. These results suggest that the marginal effects of emissions prices may vary greatly with the level of emissions abatement and the fundamental characteristics of the market.

The question of what constitutes optimal emissions abatement policies is complicated by the potential for the marginal cost of abatement curves to oscillate. This paper demonstrates how the incremental cost of abatement curves may intersect with a CO_2 tax at many levels of abatement, allowing for different characterizations of the 'optimum'. Disagreements over the optimum level of abatement, then, can occur even if parties agree completely on the marginal costs and marginal benefits of abatement, complicating the formation of public policy.

CHAPTER 5
CONCLUDING REMARKS AND OPPORTUNITIES FOR FURTHER RESEARCH

The provision of electricity is critical to life in the United States, and a better understanding of the effects and challenges of changes in the sector can lead to improvements in consumer and producer welfare. The electricity industry has experienced significant changes over the last twenty years, new structure and new priorities, and analysis of the effects of these changes can advance this understanding.

Electric restructuring led to a change in the organization of the electricity industry in the United States. The problems that have accompanied this restructuring have received a considerable amount of attention, but it is also important to consider the benefits that have accrued. New organizations to faciliatate access to the transmission grid have resulted in opportunities, but as discussed here, no significant price effects for consumers. And while access to the grid has resulted in more participation in the wholesale market, this benefit of access has not been universally exploited. These are not the only possible benefits of RTOs, however. RTOs may also improve system reliability and improve the long term planning process for generation and transmission resources. These questions are not addressed here and remain avenues for further research.

Another challenge facing the electricity industry centers on the the externalities associated with the emission of greenhouse gases during the combustion of fossil fuels. Most of the work inthis area has focues on the quantification of the costs and benefits of emissions abatement, and the theoretical perspective on what constitutes an optimal level of emissions abatement. However, these models rely on cost and benefit curves that are well-behaved in the economic sense. But this assumption of well-behaved cost curves may not be a valid one. I have derived the curves for electricity generation in Florida here, but the model could be generalized

and the scope could be expanded in further research. Indeed, an understanding of the marginal cost curves for the electricity generation and transportation sectors is crucial to the question of what constitutes an optimal level of abatement for the United States. The challenges we face are formidable, but we have tools with which to address them, and I hope that we can advance our understanding of these issues, to the benefit of society.

APPENDIX A
TEST OF ENDOGENEITY OF SALES

To test whether *ΔlnSales* is endogenous in Equation 2-2, Equation A-1 is estimated

$$\Delta lnSales = \beta_0 \Delta lnPop + \beta_1 \Delta lnPCI + \beta_2 \Delta lnCDD + \beta_3 \Delta lnHDD + \beta_4 \Delta lnPCoal + \beta_5 \Delta lnPGas + \beta_6 \Delta\%Hydro + \beta_7 \Delta\%Nuc + \beta_8 \Delta RTO + \beta_9 \Delta RTO_{t-1} + \beta_{10} \Delta RTO_{t-2} + \varepsilon_{it} \quad \text{(A-1)}$$

Where:

Pop	State population
PCI	State per capita income
CDD	State population-weighted cooling degree days
HDD	State population-weighted heating degree days
Sales	Electricity sales
PCoal	Nominal price of coal
PGas	Nominal price of natural gas
%Hydro	Percent of electric generation from hydroelectric sources
%Nuc	Percent of electric generation from nuclear sources
RTO	Whether the majority of the electric customers in the state are served by a utility that belongs to an RTO

The results of this estimation are shown in Table A-1. The residuals from this reduced form estimation are included as independent variables in the estimation of Equation 2-2. The coefficient on the residuals is significant at the 1% level[1], indicating that the variable *Sales* is

[1] Coefficient was -0.6788 with a standard error of 0.1175

endogenous in Equation 2-2. Therefore, Equation 2-2 is estimated with the two stage least squares technique (2SLS) utilizing the variables *ΔlnHDD*, *ΔlnCDD*, *ΔlnPCI,* and *ΔlnPop* as instrumental variables for *ΔlnSales*.

Table A-1. OLS estimates of the log return of electric sales

Variable	Coefficient
Constant	0.0053
	(0.0033)
ΔlnPop	0.5659***
	(0.0802)
ΔlnPCI	0.2200***
	(0.0512)
ΔlnCDD	0.0436***
	(0.0052)
ΔlnHDD	0.0982***
	(0.0152)
ΔlnPCoal	-0.0393***
	(0.0141)
ΔlnPGas	-0.0131***
	(0.0044)
Δ%Hydro	0.1431***
	(0.0498)
Δ%Nuc	0.0042
	(0.0276)
RTO	-0.0020
	(0.0027)
RTO_{t-1}	-0.0017
	(0.0034)
RTO_{t-2}	0.0070**
	(0.0035)

R-squared of 0.22
F-test statistic is 15.70 and significant at the 1% level
(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

APPENDIX B
TEST OF THE STRENGTH OF INSTUMENTAL VARIABLES

The results of the first stage regressions of the estimates of Equation 2-2 are provided below. Table B-1 and Table B-2 apply to the entire sample, while Table B-3 and Table B-4 apply to the restricted sample.

Table B-1. First stage estimates of log return of electricity sales with entire sample

Variable	Coefficient
Constant	0.0053
	(0.0032)
ΔlnPCoal	-0.0393***
	(0.0141)
ΔlnPGas	-0.0131***
	(0.0044)
Δ%Hydro	0.1431***
	(0.0498)
Δ%Nuc	0.0042
	(0.0276)
RTO	-0.0020
	(0.0027)
RTO_{t-1}	-0.0017
	(0.0034)
RTO_{t-2}	0.0070**
	(0.0035)
ΔlnCDD	0.0436***
	(0.0052)
ΔlnHDD	0.0982***
	(0.0152)
ΔlnPop	0.5659***
	(0.0802)
ΔlnPCI	0.2200***
	(0.0512)

R-squared of 0.22
(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

Table B-2. Partial R^2 values for excluded instruments

Variable	Partial R^2
ΔlnCDD	0.1101
ΔlnHDD	0.0626
ΔlnPop	0.0394
ΔlnPCI	0.0171

All of the coefficients on the IV for sales are significant at the 1% level. Additionally, the Cragg-Donald Wald F-statistic for this regression is 47.83, and exceeds the 5% critical value from Stock and Yogo (2005) at the 5% level, so the null hypothesis that the instrumental variables are weak in this estimation is rejected.

Table B-3. First stage estimates of log return of electricity sales excluding restructured states

Variable	Coefficient
Constant	0.0092**
	(0.0041)
ΔlnPCoal	-0.0291
	(0.0193)
ΔlnPGas	-0.0185***
	(0.0053)
Δ%Hydro	0.1820***
	(0.0678)
Δ%Nuc	0.0033
	(0.0596)
RTO	-0.0049
	(0.0032)
RTO_{t-1}	-0.0002
	(0.0039)
RTO_{t-2}	0.0114***
	(0.0040)
ΔlnCDD	0.0465***
	(0.0072)
ΔlnHDD	0.0856***
	(0.0167)
ΔlnPop	0.4930***
	(0.1028)
ΔlnPCI	0.2116***
	(0.0584)

R-squared of 0.21
(Robust standard errors clustered by state in parentheses)
* Statistically significant at the 10% level
** Statistically significant at the 5% level
*** Statistically significant at the 1% level

Table B-4. Partial R^2 values for excluded instruments

Variable	Partial R^2
ΔlnCDD	0.1154
ΔlnHDD	0.0475
ΔlnPop	0.0327
ΔlnPCI	0.0163

Again, all of the coefficients on the IVs for kWh sales are significant at the 1% level, and the Cragg-Donald Wald F-statistic for this regression is 30.04, and exceeds the 5% critical value from Stock and Yogo (2005) at the 5% level, so the null hypothesis that the instrumental variables are weak in this estimation is rejected.

APPENDIX C
THE MODEL OF ECONOMIC DISPATCH

This appendix provides details on the operation and use of the model that solves the problem of least cost dispatch of the electricity generation system.

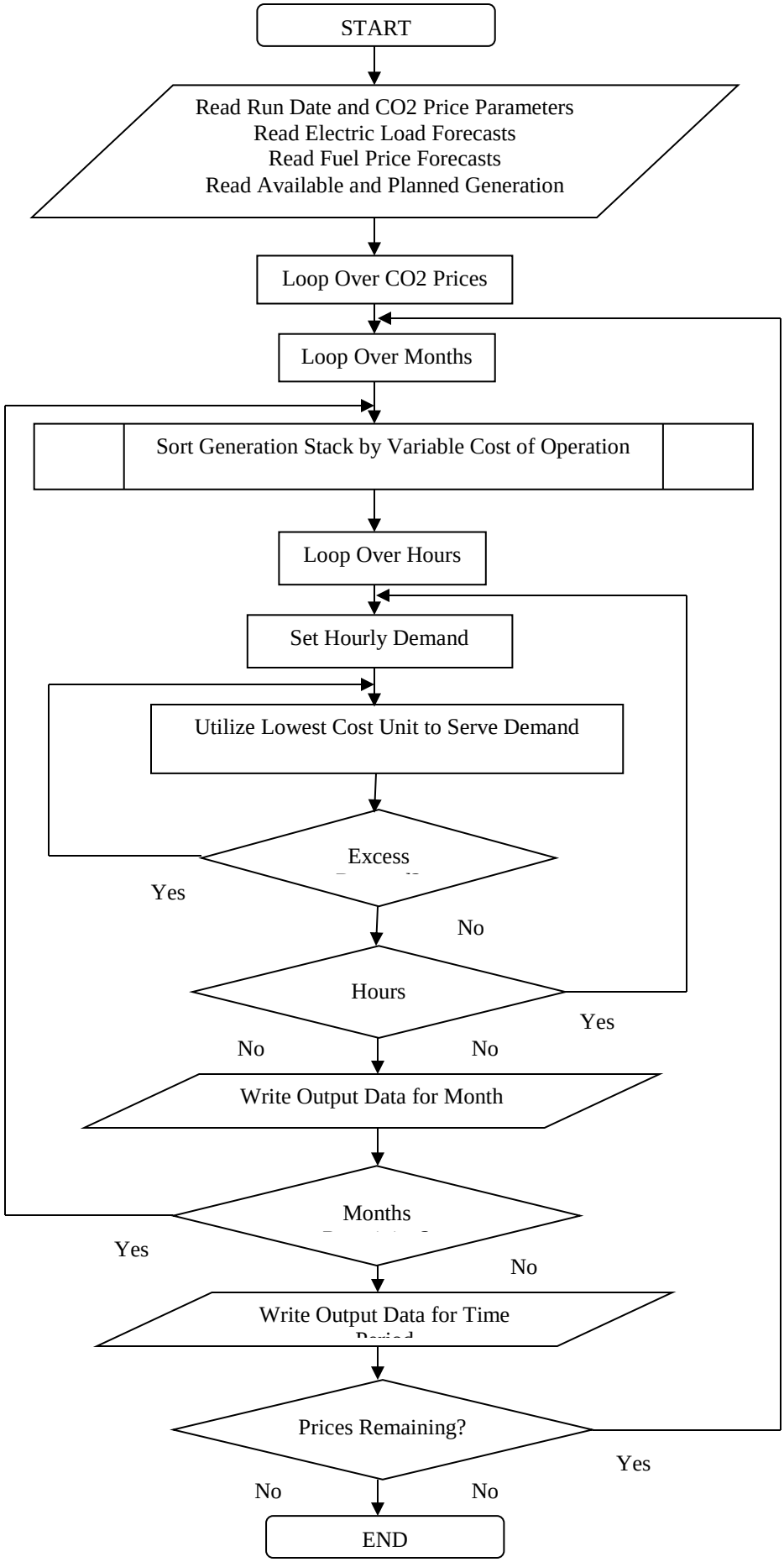
Main Routine

The *Main* routine acts a program shell that calls all of the other subroutines and manages the main program loop, the hourly system dispatch. The routine begins by calling the routines *WriteInputLoad*, *WriteInputFuelPrice*, and *WriteInputGenUnits*. These routines archive the input data used to create the run: the hourly MWh load, the fuel prices, and the beginning generating units for the system. It then reads in the parameters for the beginning and ending dates, and the high, low, and interval CO_2 prices used in the simulation. The module loads the generating units used and loads each data element associated with the unit. Any missing elements are assigned default ratings for that particular generator type. The data elements include:

- Owner
- Plant Name
- Unit Number
- Type of generator
- Summer Capacity Rating in MW
- Winter Capacity Rating in MW
- Unit Availability Percentage
- Unit Heat Rate
- Variable Operating and Maintenance Expenses in $/MWh
- The number of fuels utilized by the plant
- Availability date of the unit
- Retirement date of the unit

The program then begins the main operating loop over the CO_2 prices for the run. There are also nested loops over the months over the simulation time period and the hours in each month. Within each month, the fuel and emissions prices are used to rank the different generators available from lowest variable cost of operation to greatest. Then, within each hour of the month,

units are dispatched to serve the hourly electric load until the demand is satisfied. The hourly marginal cost of generation is added to a flat file. The model then repeats this dispatch process for each hour of the month. Once the month has been simulated, the model repeats the rank-ordering process for the next month, updating the fuel prices used in the simulation. Once all of the time periods have been processed, the model repeats the process with the new CO_2 price. The model writes detailed output on costs and generator statistics to a flat file in comma-delimited format, and aggregate output to tabs of the Excel workbook. A description of each intermediate subroutine and function follows.


START
Read Run Date and CO2 Price Parameters
Read Electric Load Forecasts
Read Fuel Price Forecasts
Read Available and Planned Generation
Loop Over CO2 Prices
Loop Over Months
Sort Generation Stack by Variable Cost of Operation
Loop Over Hours
Set Hourly Demand
Utilize Lowest Cost Unit to Serve Demand
Excess
Yes
No
Hours
Yes
No
No
Write Output Data for Month
Months
Yes
No
Write Output Data for Time
Prices Remaining?
Yes
No
No
END

```
' All code written by
' Ted Kury
' Director of Energy Studies
' Public Utility Research Center

Option Explicit

Type GenFuel
    Name As String
    Index As String
    Type As String
    Adder As Double
    TypeIndex As Long
    PriceIndex As Long
End Type

Type GenFuelBurn
    Type As String
    BurnMMBtu As Double
End Type

Type GenPlant
    Owner As String
    PlantName As String
    UnitName As String
    PlantType As String
    DEPTypeCode As String
    DEPCapUnit As Integer
    SumCap As Double
    WinCap As Double
    HeatRate As Double
    VOM As Double
    AvailPct As Double
    NumFuels As Integer
    Fuel() As GenFuel
    CCS As Double               'Percentage of emissions captured,
default is 0
    AvailDate As Date
    RetireDate As Date
    DispatchFlag As Long
    LevelCost As Double
    FixedCost As Double
End Type

Type PlantOutput
    MWh As Double
    FuelCost As Double
    FuelBurn() As GenFuelBurn
    VOMCost As Double
End Type

Dim dLoadShape() As Double
```

```
Dim aGenUnits() As GenPlant
Dim aOutput() As PlantOutput
Dim dGenStack() As Double
Dim dMaxMWhByFuel() As Double
Dim dCarbonPrice As Double
Dim dtBeginDate As Date
Dim dtEndDate As Date
Dim lGenCnt As Long
Dim bConstrainGenPort As Boolean
```

```
Sub Main()

Dim dDispatch() As Double
Dim dDispatchSum() As Double
Dim dAnnualSum() As Double
Dim dAnnualSumType() As Double
Dim dAnnualSumVintage() As Double
Dim dAggregateSum() As Double
Dim dAggregateFuelCosts() As Double
Dim dAggregateFuelMMBtu() As Double
Dim dREMIFuelData() As Double

Dim i As Long
Dim j As Long
Dim k As Long
Dim m As Long

Dim dTemp As Double
Dim dTempMWh As Double
Dim dMaxLoad As Double
Dim dGenCap As Double
Dim dReserveMargin As Double
Dim tempPlant As GenPlant
Dim iFuels As Integer
Dim iPlantIdx As Integer
Dim dtCurrDate As Date
Dim iHours As Integer
Dim dCarbonHigh As Double           'Carbon price upper bound
Dim dCarbonLow As Double
Dim dCarbonInt As Double
Dim dHourlyCap As Double
Dim dSeasonalCap As Double
Dim iDateIdx As Integer
Dim iDateCnt As Integer
Dim iTemp As Integer
Dim iLoadShapeIdx As Integer
Dim iDEPTypeIdx As Integer
Dim iNumDEPTypes As Integer
Dim iNumFuelTypes As Integer        'Number of fuel types
Dim lLoadDateIdx As Long
Dim lOutRow As Long                 'Row for summary output
Dim lAggOutRow As Long
Dim lAggSectionOffset As Long
Dim lInitialGenCnt As Long          'Number of stock plants before
additions
Dim dtLoadDate As Date
Dim sDir As String
Dim sOutfile As String
Dim sUnitFile As String
Dim sPriceFile As String
Dim sOutstring As String
Dim sREMIFile As String
```

```
Dim oldStatusBar As String
Dim dElapsedRunTime As Double
Dim dTotalRunTime As Double
Dim dFixedCostAdjust As Double
Dim dFixedGenCost As Double
Dim dNewGenCost As Double

Dim NewPlant() As GenPlant

iNumDEPTypes = 12
dReserveMargin = 0.15
dFixedCostAdjust = 58

oldStatusBar = Application.DisplayStatusBar
Application.DisplayStatusBar = True

Application.ScreenUpdating = False

sDir = ActiveWorkbook.Path & "\" & Format(Now(), "yymmddhhmm") & "\"
'get path of workbook
MkDir sDir

Call WriteInputLoad(sDir)
Call WriteInputFuelPrice(sDir)
Call WriteInputGenUnits(sDir)

sOutfile = "PlantOutput.csv"
sUnitFile = "NewUnits.csv"
sPriceFile = "MarginalCosts.csv"
sREMIFile = "REMIInputs.csv"

Open sDir & sOutfile For Output As #1
Open sDir & sUnitFile For Output As #2
Open sDir & sPriceFile For Output As #3
Open sDir & sREMIFile For Output As #4

'Read in run parameters
dtBeginDate = Range("BegDate")
dtEndDate = Range("EndDate")
iDateIdx = DateDiff("m", dtBeginDate, dtEndDate)

'Read in carbon price parameters
dCarbonHigh = Range("CarbonHigh")
dCarbonLow = Range("CarbonLow")
dCarbonInt = Range("CarbonInt")

bConstrainGenPort = Range("GenPortCheckStatus")

dTotalRunTime = (iDateIdx + 1) * (((dCarbonHigh - dCarbonLow) /
dCarbonInt) + 1)

'Find number of fuel types
```

```
Do Until IsEmpty(Sheet5.Cells(iNumFuelTypes + 2, 7))
    iNumFuelTypes = iNumFuelTypes + 1
Loop
iNumFuelTypes = iNumFuelTypes - 1

ReDim dMaxMWhByFuel(iNumFuelTypes, 1)
'Element 0 is Row Number
'Element 1 is MWh limit

Call GetPortConstraint

'Clear output sheets

Sheet4.Range("A2:AE65536").Clear
Sheet9.Range("A1:AF65536").Clear
Sheet10.Range("A2:P65536").Clear
Sheet13.Range("A3:BE65536").Clear

'Read in generating units
lGenCnt = 0
Do Until IsEmpty(Sheet1.Cells(lGenCnt + 2, 1))
    iPlantIdx = 0
    ReDim Preserve aGenUnits(lGenCnt)
    aGenUnits(lGenCnt).Owner = Sheet1.Cells(lGenCnt + 2, 1)
    aGenUnits(lGenCnt).PlantName = Sheet1.Cells(lGenCnt + 2, 2)
    aGenUnits(lGenCnt).UnitName = Sheet1.Cells(lGenCnt + 2, 3)
    aGenUnits(lGenCnt).PlantType = Sheet1.Cells(lGenCnt + 2, 4)
    aGenUnits(lGenCnt).SumCap = Sheet1.Cells(lGenCnt + 2, 6)
    aGenUnits(lGenCnt).WinCap = Sheet1.Cells(lGenCnt + 2, 7)
    aGenUnits(lGenCnt).AvailPct = Sheet1.Cells(lGenCnt + 2, 8)
    aGenUnits(lGenCnt).HeatRate = Sheet1.Cells(lGenCnt + 2, 9)
    aGenUnits(lGenCnt).VOM = Sheet1.Cells(lGenCnt + 2, 10)
    aGenUnits(lGenCnt).NumFuels = Sheet1.Cells(lGenCnt + 2, 11)
    aGenUnits(lGenCnt).AvailDate = Sheet1.Cells(lGenCnt + 2, 18)
    aGenUnits(lGenCnt).RetireDate = Sheet1.Cells(lGenCnt + 2, 20)
    aGenUnits(lGenCnt).DEPCapUnit = Sheet1.Cells(lGenCnt + 2, 21)
    aGenUnits(lGenCnt).DEPTypeCode = Sheet1.Cells(lGenCnt + 2, 22)
    aGenUnits(lGenCnt).DispatchFlag = Sheet1.Cells(lGenCnt + 2, 19)
    iFuels = Sheet1.Cells(lGenCnt + 2, 11) - 1
    ReDim aGenUnits(lGenCnt).Fuel(iFuels)
    For i = 0 To iFuels
        aGenUnits(lGenCnt).Fuel(i).Type = Sheet1.Cells(lGenCnt + 2, i
+ 12)
        aGenUnits(lGenCnt).Fuel(i).Adder = Sheet1.Cells(lGenCnt + 2, i
+ 15)
        aGenUnits(lGenCnt).Fuel(i).TypeIndex =
GetFuelIndex(aGenUnits(lGenCnt).Fuel(i).Type)
        aGenUnits(lGenCnt).Fuel(i).PriceIndex =
GetFuelPriceIndex(aGenUnits(lGenCnt).Fuel(i).Type)
    Next i
    'Check for missing plant data and fill in the blanks
    If IsEmpty(Sheet1.Cells(lGenCnt + 2, 8)) Then
```

```
        iPlantIdx = PlantTypeLookup(aGenUnits(lGenCnt).PlantType,
aGenUnits(lGenCnt).Fuel(0).Type)
        aGenUnits(lGenCnt).AvailPct = Sheet5.Cells(iPlantIdx + 1, 5)
    End If
    If IsEmpty(Sheet1.Cells(lGenCnt + 2, 9)) Then
        If iPlantIdx = 0 Then iPlantIdx =
PlantTypeLookup(aGenUnits(lGenCnt).PlantType,
aGenUnits(lGenCnt).Fuel(0).Type)
        aGenUnits(lGenCnt).HeatRate = Sheet5.Cells(iPlantIdx + 1, 3)
    End If
    If IsEmpty(Sheet1.Cells(lGenCnt + 2, 10)) Then
        If iPlantIdx = 0 Then iPlantIdx =
PlantTypeLookup(aGenUnits(lGenCnt).PlantType,
aGenUnits(lGenCnt).Fuel(0).Type)
        aGenUnits(lGenCnt).VOM = Sheet5.Cells(iPlantIdx + 1, 4)
    End If
    If IsEmpty(Sheet1.Cells(lGenCnt + 2, 18)) Then
aGenUnits(lGenCnt).AvailDate = #1/1/1980#
    If IsEmpty(Sheet1.Cells(lGenCnt + 2, 20)) Then
aGenUnits(lGenCnt).RetireDate = #1/1/2080#
    lGenCnt = lGenCnt + 1
Loop

lGenCnt = lGenCnt - 1
lInitialGenCnt = lGenCnt

'Start loop by carbon prices and by date

lOutRow = 2
lAggOutRow = 2
For dCarbonPrice = dCarbonLow To dCarbonHigh Step dCarbonInt
    dFixedGenCost = 0
    lGenCnt = lInitialGenCnt
    ReDim Preserve aGenUnits(lGenCnt)
    lLoadDateIdx = dtBeginDate - Sheet3.Cells(1, 1) + 1
    'Determine least cost form or input mix of new generation
    Call DefineNewPlant(NewPlant, dCarbonPrice)
    dNewGenCost = PriceNewPlant(NewPlant)
    ReDim dDispatchSum(iNumFuelTypes, 3, lGenCnt)
    ReDim dAnnualSum(iNumFuelTypes, 3)
    ReDim dAnnualSumVintage(1, iNumFuelTypes, 3)
    ReDim dAggregateFuelCosts(iNumFuelTypes, 3)
    ReDim dAggregateFuelMMBtu(iNumFuelTypes)
    ReDim dAnnualSumType(iNumDEPTypes, 3)
    ReDim dAggregateSum(3)
    For iDateCnt = 0 To iDateIdx
        Application.StatusBar = "Program " & Round(dElapsedRunTime /
dTotalRunTime * 100, 0) & "% Completed"
        dtCurrDate = DateAdd("m", iDateCnt, dtBeginDate)
        iHours = (DateAdd("m", 1, dtCurrDate) - dtCurrDate) * 24 - 1
        ReDim dLoadShape(iHours)
'Read in load file
```

```
        iLoadShapeIdx = 0
        dMaxLoad = 0
        Do
            For i = 2 To 25
                dLoadShape(iLoadShapeIdx) = Sheet3.Cells(lLoadDateIdx,
i)
                If Sheet3.Cells(lLoadDateIdx, i) > dMaxLoad Then
dMaxLoad = Sheet3.Cells(lLoadDateIdx, i)
                iLoadShapeIdx = iLoadShapeIdx + 1
            Next i
            lLoadDateIdx = lLoadDateIdx + 1
            dtLoadDate = Sheet3.Cells(lLoadDateIdx, 1)
        Loop While Month(dtLoadDate) = Month(dtCurrDate) And
Year(dtLoadDate) = Year(dtCurrDate)

        'Check to add new generating units
        dGenCap = 0
        For i = 0 To lGenCnt
            If dtCurrDate >= aGenUnits(i).AvailDate And dtCurrDate <
aGenUnits(i).RetireDate Then
                Select Case Month(dtCurrDate)
                Case 5 To 9
                    dGenCap = dGenCap + aGenUnits(i).SumCap
                Case Else
                    dGenCap = dGenCap + aGenUnits(i).WinCap
                End Select
            End If
        Next i

        dMaxLoad = dMaxLoad * (1 + dReserveMargin)

        If dGenCap < dMaxLoad Then
            dTemp = dMaxLoad - dGenCap
            Do Until dTemp < 0
                If Not Range("CheckBoxStatus") Then
                    j = 0
                Else
                    j = UBound(NewPlant)
                End If
                For i = 0 To j
                    lGenCnt = lGenCnt + 1
                    ReDim Preserve aGenUnits(lGenCnt)
                    ReDim Preserve dDispatchSum(iNumFuelTypes, 3,
lGenCnt)
                    aGenUnits(lGenCnt) = NewPlant(i)
                    aGenUnits(lGenCnt).AvailDate = dtCurrDate
                    aGenUnits(lGenCnt).RetireDate = DateAdd("yyyy",
50, dtCurrDate)
                    dFixedGenCost = dFixedGenCost +
aGenUnits(lGenCnt).FixedCost
                    sOutstring = dCarbonPrice & "," & dtCurrDate & ","
& aGenUnits(lGenCnt).SumCap & "," & aGenUnits(lGenCnt).PlantName
```

```
                    Print #2, sOutstring
                Next i
                dTemp = dTemp - 1000
            Loop
        End If

        Call SetGenStack(dtCurrDate, dCarbonPrice)

        Call BubbleSortGenStack(1)

        ReDim dDispatch(lGenCnt + 30, iHours, iNumFuelTypes, 3)
        'dDispatch elements are:
        '   0   Dispatch MW
        '   1   Variable costs (fuel, emissions, VOM)
        '   2   Emissions
        '   3   Fuel Burn

        For i = 0 To iHours
            dTemp = dLoadShape(i)
            If bConstrainGenPort Then
                For j = 0 To UBound(dMaxMWhByFuel)
                    If dMaxMWhByFuel(j, 0) <> 0 Then
                        dMaxMWhByFuel(j, 1) = dTemp *
Sheet14.Cells(dMaxMWhByFuel(j, 0), Year(dtCurrDate) - 2007)
                    End If
                Next j
            End If
            j = 0
            Do Until dTemp <= 0
                If j > UBound(dGenStack, 2) Then
                'Add a new plant
                    If Not Range("CheckBoxStatus") Then
                        m = 0
                        Do
                            k = NewPlant(m).Fuel(0).TypeIndex
                            If dMaxMWhByFuel(k - 2, 1) <> -1 Then
                                lGenCnt = lGenCnt + 1
                                ReDim Preserve aGenUnits(lGenCnt)
                                ReDim Preserve
dDispatchSum(iNumFuelTypes, 3, lGenCnt)
                                aGenUnits(lGenCnt) = NewPlant(m)
                                aGenUnits(lGenCnt).AvailDate =
dtCurrDate
                                aGenUnits(lGenCnt).RetireDate =
DateAdd("yyyy", 50, dtCurrDate)
                                dFixedGenCost = dFixedGenCost +
aGenUnits(lGenCnt).FixedCost
                                Call AddGenStack(dGenStack,
NewPlant(m), lGenCnt)
                                sOutstring = dCarbonPrice & "," &
dtCurrDate & "," & aGenUnits(lGenCnt).SumCap & "," &
aGenUnits(lGenCnt).PlantName
```

```
                                Print #2, sOutstring
                                Exit Do
                            Else
                                m = m + 1
                            End If
                        Loop
                    Else
                        m = UBound(NewPlant)
                        For k = 0 To m
                            lGenCnt = lGenCnt + 1
                            ReDim Preserve aGenUnits(lGenCnt)
                            ReDim Preserve dDispatchSum(iNumFuelTypes,
3, lGenCnt)
                            aGenUnits(lGenCnt) = NewPlant(k)
                            aGenUnits(lGenCnt).AvailDate = dtCurrDate
                            aGenUnits(lGenCnt).RetireDate =
DateAdd("yyyy", 50, dtCurrDate)
                            dFixedGenCost = dFixedGenCost +
aGenUnits(lGenCnt).FixedCost
                            Call AddGenStack(dGenStack, NewPlant(k),
lGenCnt)
                            sOutstring = dCarbonPrice & "," &
dtCurrDate & "," & aGenUnits(lGenCnt).SumCap & "," &
aGenUnits(lGenCnt).PlantName
                            Print #2, sOutstring
                        Next k
                    End If
                End If
                tempPlant = aGenUnits(dGenStack(0, j))
                Select Case Month(dtCurrDate)
                Case 1, 2
                    dHourlyCap = tempPlant.WinCap
                    dSeasonalCap = 0.05
                Case 3, 4, 10, 11, 12
                    dHourlyCap = tempPlant.WinCap
                    dSeasonalCap = -0.05
                Case 5
                    dHourlyCap = tempPlant.SumCap
                    dSeasonalCap = -0.05
                Case 6 To 9
                    dHourlyCap = tempPlant.SumCap
                    dSeasonalCap = 0.05
                End Select
                If tempPlant.AvailPct + dSeasonalCap > 1 Then
dSeasonalCap = 1 - tempPlant.AvailPct
                If tempPlant.AvailPct + dSeasonalCap < 0 Then
dSeasonalCap = -tempPlant.AvailPct
                dHourlyCap = dHourlyCap * (tempPlant.AvailPct +
dSeasonalCap)
                Select Case dMaxMWhByFuel(dGenStack(2, j) - 2, 1)
                Case -1
                    dHourlyCap = 0
```

```
                Case Is > 0
                    dMaxMWhByFuel(dGenStack(2, j) - 2, 1) =
dMaxMWhByFuel(dGenStack(2, j) - 2, 1) - dHourlyCap
                    If dMaxMWhByFuel(dGenStack(2, j) - 2, 1) <= 0 Then
dMaxMWhByFuel(dGenStack(2, j) - 2, 1) = -1
                End Select
                If dTemp > dHourlyCap Then
                    dDispatch(dGenStack(0, j), i, dGenStack(2, j) - 2,
0) = dHourlyCap
                    dDispatch(dGenStack(0, j), i, dGenStack(2, j) - 2,
1) = dHourlyCap * dGenStack(1, j)
                    dDispatch(dGenStack(0, j), i, dGenStack(2, j) - 2,
2) = dHourlyCap * dGenStack(4, j)
                    dDispatch(dGenStack(0, j), i, dGenStack(2, j) - 2,
3) = dHourlyCap * dGenStack(3, j)
                    dTemp = dTemp - dHourlyCap
                Else
                    dDispatch(dGenStack(0, j), i, dGenStack(2, j) - 2,
0) = dTemp
                    dDispatch(dGenStack(0, j), i, dGenStack(2, j) - 2,
1) = dTemp * dGenStack(1, j)
                    dDispatch(dGenStack(0, j), i, dGenStack(2, j) - 2,
2) = dTemp * dGenStack(4, j)
                    dDispatch(dGenStack(0, j), i, dGenStack(2, j) - 2,
3) = dTemp * dGenStack(3, j)
                    dTemp = 0
                    sOutstring = dCarbonPrice & "," & dtCurrDate & ","
& i & "," & dGenStack(1, j)
                    Print #3, sOutstring
                End If
                j = j + 1
            Loop
        '    For j = 0 To lGenCnt
        '        Sheet4.Cells(i + 1, j + 1) = dDispatch(j, i)
        '    Next j
        Next i

    'Aggregate monthly dispatch results
    'dDispatchSum elements are:
    '   Fuel types
    '   Element (MW,VC,CO2,MMBtu)
    '   GenID
        For i = 0 To lGenCnt
            iDEPTypeIdx = DEPTypeLookup(aGenUnits(i).DEPTypeCode)
            For j = 0 To iHours
                For k = 0 To iNumFuelTypes
                    For m = 0 To 3
                        dDispatchSum(k, m, i) = dDispatchSum(k, m, i)
+ dDispatch(i, j, k, m)
                        Select Case aGenUnits(i).AvailDate
                        Case Is < #1/1/2009#
```

```
                            dAnnualSumVintage(0, k, m) =
dAnnualSumVintage(0, k, m) + dDispatch(i, j, k, m)
                        Case Else
                            dAnnualSumVintage(1, k, m) =
dAnnualSumVintage(1, k, m) + dDispatch(i, j, k, m)
                        End Select
                        dAnnualSumType(iDEPTypeIdx, m) =
dAnnualSumType(iDEPTypeIdx, m) + dDispatch(i, j, k, m)
                    Next m
                    dAggregateFuelMMBtu(k) = dAggregateFuelMMBtu(k) +
dDispatch(i, j, k, 3)
                Next k
            Next j
        Next i
        'Calculate Aggregate Fuel Costs
        For i = 0 To iNumFuelTypes
            dTemp = Sheet2.Cells(DateDiff("m", Sheet2.Cells(2, 1),
dtCurrDate) + 2, GetFuelPriceIndex(Sheet5.Cells(i + 2, 7))) 'Fuel
Price
            dAggregateFuelCosts(i, 0) = dAggregateFuelCosts(i, 0) +
dAggregateFuelMMBtu(i) * dTemp
        Next i
        ReDim dAggregateFuelMMBtu(iNumFuelTypes)

    'Write annual results
        If Month(dtCurrDate) = 12 Or iDateCnt = iDateIdx Then
            'Write individual generator records
            For i = 0 To lGenCnt
                dTemp = (5 * aGenUnits(i).SumCap + 7 *
aGenUnits(i).WinCap) / 12
                dTempMWh = 0
                sOutstring = Year(dtCurrDate)
                sOutstring = sOutstring & "," & dCarbonPrice
                sOutstring = sOutstring & "," & i
                For j = 0 To 3
                    For k = 0 To iNumFuelTypes
                        sOutstring = sOutstring & "," &
dDispatchSum(k, j, i)
                        If j = 0 Then dTempMWh = dTempMWh +
dDispatchSum(k, j, i)
                        dAnnualSum(k, j) = dAnnualSum(k, j) +
dDispatchSum(k, j, i)
                    Next k
                Next j
                'Write output line for individual generator
                sOutstring = sOutstring & "," & dTempMWh / (dTemp *
8760)
                Print #1, sOutstring
            Next i
            'Write annual summaries and reset summary arrays
            'Write Output detail by fuel type and DEP type
```

```
            lAggSectionOffset = CLng((dCarbonHigh - dCarbonLow) /
dCarbonInt) + 1
            For i = 0 To 3
                Sheet4.Cells(lOutRow, 1) = dCarbonPrice
                Sheet4.Cells(lOutRow, 2) = Year(dtCurrDate)
                Sheet10.Cells(lOutRow, 1) = dCarbonPrice
                Sheet10.Cells(lOutRow, 2) = Year(dtCurrDate)
                Sheet13.Cells(lOutRow + 1, 1) = dCarbonPrice
                Sheet13.Cells(lOutRow + 1, 2) = Year(dtCurrDate)
                Select Case i
                Case 0
                    Sheet4.Cells(lOutRow, 3) = "MWh"
                    Sheet10.Cells(lOutRow, 3) = "MWh"
                    Sheet13.Cells(lOutRow + 1, 3) = "MWh"
                Case 1
                    Sheet4.Cells(lOutRow, 3) = "Variable Costs"
                    Sheet10.Cells(lOutRow, 3) = "Variable Costs"
                    Sheet13.Cells(lOutRow + 1, 3) = "Variable Costs"
                Case 2
                    Sheet4.Cells(lOutRow, 3) = "Emissions"
                    Sheet10.Cells(lOutRow, 3) = "Emissions"
                    Sheet13.Cells(lOutRow + 1, 3) = "Emissions"
                Case 3
                    Sheet4.Cells(lOutRow, 3) = "Fuel Burn"
                    Sheet10.Cells(lOutRow, 3) = "Fuel Burn"
                    Sheet13.Cells(lOutRow + 1, 3) = "Fuel Burn"
                End Select
                For j = 0 To iNumFuelTypes
                    Sheet4.Cells(lOutRow, 4 + j) = dAnnualSum(j, i)
                    Sheet13.Cells(lOutRow + 1, 4 + j) =
dAnnualSumVintage(0, j, i)
                    Sheet13.Cells(lOutRow + 1, 5 + iNumFuelTypes + j)
= dAnnualSumVintage(1, j, i)
                    dAggregateSum(i) = dAggregateSum(i) +
dAnnualSum(j, i)
                Next j
                For j = 0 To UBound(dAnnualSumType, 1)
                    Sheet10.Cells(lOutRow, 4 + j) = dAnnualSumType(j,
i)
                Next j
                lOutRow = lOutRow + 1
            Next i
            'Write Aggregated Annual Output
            If lAggOutRow = 2 Then
            'Set section headers
                Sheet9.Cells(1, 1) = "MWh"
                Sheet9.Cells(4, 1) = "Variable Costs"
                Sheet9.Cells(lAggSectionOffset + 6, 1) = "Emissions"
                Sheet9.Cells(lAggSectionOffset * 2 + 8, 1) = "Average
Variable Costs"
            End If
```

```
            Sheet9.Cells(1, Year(dtCurrDate) - Year(dtBeginDate) + 2)
= Year(dtCurrDate)
            Sheet9.Cells(2, Year(dtCurrDate) - Year(dtBeginDate) + 2)
= dAggregateSum(0)

            Sheet9.Cells(4, Year(dtCurrDate) - Year(dtBeginDate) + 2)
= Year(dtCurrDate)
            Sheet9.Cells(lAggOutRow + 3, 1) = dCarbonPrice
            Sheet9.Cells(lAggOutRow + 3, Year(dtCurrDate) -
Year(dtBeginDate) + 2) = dAggregateSum(1)

            Sheet9.Cells(lAggSectionOffset + 6, Year(dtCurrDate) -
Year(dtBeginDate) + 2) = Year(dtCurrDate)
            Sheet9.Cells(lAggSectionOffset + lAggOutRow + 5, 1) =
dCarbonPrice
            Sheet9.Cells(lAggSectionOffset + lAggOutRow + 5,
Year(dtCurrDate) - Year(dtBeginDate) + 2) = dAggregateSum(2)

            Sheet9.Cells(lAggSectionOffset * 2 + 8, Year(dtCurrDate) -
Year(dtBeginDate) + 2) = Year(dtCurrDate)
            Sheet9.Cells(lAggSectionOffset * 2 + lAggOutRow + 7, 1) =
dCarbonPrice
            Sheet9.Cells(lAggSectionOffset * 2 + lAggOutRow + 7,
Year(dtCurrDate) - Year(dtBeginDate) + 2) = dAggregateSum(1) /
dAggregateSum(0)
            'Construct and Write REMI file
            For i = 0 To lGenCnt
                For j = 1 To aGenUnits(i).NumFuels
                    iTemp = aGenUnits(i).Fuel(j - 1).TypeIndex - 2
                    dAggregateFuelCosts(iTemp, 1) =
dAggregateFuelCosts(iTemp, 1) + aGenUnits(i).VOM * dDispatchSum(iTemp,
0, i)
                    dAggregateFuelCosts(iTemp, 2) =
dAggregateFuelCosts(iTemp, 2) + aGenUnits(i).Fuel(j - 1).Adder *
dDispatchSum(iTemp, 3, i)
                    dAggregateFuelCosts(iTemp, 3) =
dAggregateFuelCosts(iTemp, 3) + dDispatchSum(iTemp, 2, i) *
dCarbonPrice
                Next j
            Next i

            ReDim dREMIFuelData(2, 4)
            For i = 0 To iNumFuelTypes
                Select Case Sheet5.Cells(i + 2, 7)
                Case "NG"
                    dREMIFuelData(0, 0) = dREMIFuelData(0, 0) +
dAnnualSum(i, 3)
                    For j = 0 To 3
                        dREMIFuelData(0, j + 1) = dREMIFuelData(0, j +
1) + dAggregateFuelCosts(i, j)
                    Next j
                Case "RFO", "DFO"
```

```
                    dREMIFuelData(1, 0) = dREMIFuelData(1, 0) +
dAnnualSum(i, 3)
                    For j = 0 To 3
                        dREMIFuelData(1, j + 1) = dREMIFuelData(1, j +
1) + dAggregateFuelCosts(i, j)
                    Next j
                Case Else
                    dREMIFuelData(2, 0) = dREMIFuelData(2, 0) +
dAnnualSum(i, 3)
                    For j = 0 To 3
                        dREMIFuelData(2, j + 1) = dREMIFuelData(2, j +
1) + dAggregateFuelCosts(i, j)
                    Next j
                End Select
            Next i

            sOutstring = "Year, Carbon Price, Fuel Code, MMBtu, Fuel
Costs, VOM, Adders, Emissions Cost"
            Print #4, sOutstring
            For i = 0 To iNumFuelTypes
                sOutstring = Year(dtCurrDate) & "," & dCarbonPrice &
","
                sOutstring = sOutstring & Sheet5.Cells(i + 2, 7) & ","
                sOutstring = sOutstring & dAnnualSum(i, 3) & ","
                sOutstring = sOutstring & dAggregateFuelCosts(i, 0) &
","
                sOutstring = sOutstring & dAggregateFuelCosts(i, 1) &
","
                sOutstring = sOutstring & dAggregateFuelCosts(i, 2) &
","
                sOutstring = sOutstring & dAggregateFuelCosts(i, 3)
                Print #4, sOutstring
            Next i

            sOutstring = "Year, Carbon Price, Fuel Class, MMBtu, Fuel
Costs, VOM, Adders, Emissions Cost"
            Print #4, sOutstring
            For i = 0 To 2
                sOutstring = Year(dtCurrDate) & "," & dCarbonPrice &
","
                Select Case i
                Case 0
                    sOutstring = sOutstring & "NG,"
                Case 1
                    sOutstring = sOutstring & "Oil,"
                Case 2
                    sOutstring = sOutstring & "Other(Electricity),"
                End Select
                sOutstring = sOutstring & dREMIFuelData(i, 0) & ","
                sOutstring = sOutstring & dREMIFuelData(i, 1) & ","
                sOutstring = sOutstring & dREMIFuelData(i, 2) & ","
                sOutstring = sOutstring & dREMIFuelData(i, 3) & ","
```

```
                sOutstring = sOutstring & dREMIFuelData(i, 4)
                Print #4, sOutstring
            Next i
            sOutstring = Year(dtCurrDate) & "," & dCarbonPrice & ","
            sOutstring = sOutstring & "All,"
            sOutstring = sOutstring & dREMIFuelData(0, 0) +
dREMIFuelData(1, 0) + dREMIFuelData(2, 0) & ","
            sOutstring = sOutstring & dREMIFuelData(0, 1) +
dREMIFuelData(1, 1) + dREMIFuelData(2, 1) & ","
            sOutstring = sOutstring & dREMIFuelData(0, 2) +
dREMIFuelData(1, 2) + dREMIFuelData(2, 2) & ","
            sOutstring = sOutstring & dREMIFuelData(0, 3) +
dREMIFuelData(1, 3) + dREMIFuelData(2, 3) & ","
            sOutstring = sOutstring & dREMIFuelData(0, 4) +
dREMIFuelData(1, 4) + dREMIFuelData(2, 4)
            Print #4, sOutstring

            sOutstring = "Year, Carbon Price, Consumer Price"
            Print #4, sOutstring
            sOutstring = Year(dtCurrDate) & "," & dCarbonPrice & "," &
dAggregateSum(1) / dAggregateSum(0) + dFixedCostAdjust
            Print #4, sOutstring
            sOutstring = "Year, Carbon Price, Production Cost"
            Print #4, sOutstring
            sOutstring = Year(dtCurrDate) & "," & dCarbonPrice & "," &
dAggregateSum(1)
            Print #4, sOutstring
            sOutstring = "Year, Carbon Price, Exogenous Final Demand"
            Print #4, sOutstring
            sOutstring = Year(dtCurrDate) & "," & dCarbonPrice & "," &
dAggregateSum(0)
            Print #4, sOutstring

            'Check to build new generation
'            If dAggregateSum(1) / dAggregateSum(0) + dFixedCostAdjust
> dNewGenCost Then
            If 1 > 2 Then
                If Not Range("CheckBoxStatus") Then
                    j = 0
                Else
                    j = UBound(NewPlant)
                End If
                For i = 0 To j
                    lGenCnt = lGenCnt + 1
                    ReDim Preserve aGenUnits(lGenCnt)
                    ReDim Preserve dDispatchSum(iNumFuelTypes, 3,
lGenCnt)
                    aGenUnits(lGenCnt) = NewPlant(i)
                    aGenUnits(lGenCnt).AvailDate = dtCurrDate
                    aGenUnits(lGenCnt).RetireDate = DateAdd("yyyy",
50, dtCurrDate)
```

```
                    dFixedGenCost = dFixedGenCost +
aGenUnits(lGenCnt).FixedCost
                    sOutstring = dCarbonPrice & "," & dtCurrDate & ","
& aGenUnits(lGenCnt).SumCap & "," & aGenUnits(lGenCnt).PlantName
                    Print #2, sOutstring
                Next i
            End If

            'Reset Arrays
            ReDim dDispatchSum(iNumFuelTypes, 3, lGenCnt)
            ReDim dAnnualSum(iNumFuelTypes, 3)
            ReDim dAnnualSumVintage(1, iNumFuelTypes, 3)
            ReDim dAnnualSumType(iNumDEPTypes, 3)
            ReDim dAggregateFuelCosts(iNumFuelTypes, 3)
            ReDim dAggregateSum(3)
        End If
        dElapsedRunTime = dElapsedRunTime + 1
    Next iDateCnt
    lAggOutRow = lAggOutRow + 1
Next dCarbonPrice

Close #1
Close #2
Close #3
Close #4

Application.StatusBar = False
Application.DisplayStatusBar = oldStatusBar
Application.ScreenUpdating = True

End Sub
```

Subroutine BubbleSortGenStack

The generation stack is sorted by costs for each hour of the simulation by this routine. Because the number of items is relatively small (roughly 300-400), there is little computational efficiency lost in using a straightforward Bubble sort for the procedure.

```
Sub BubbleSortGenStack(lSortIdx As Long)

'Bubble sorts array in ascending order on index lSortIdx

Dim lArrSize As Long
Dim lArrDepth As Long
Dim i As Long
Dim j As Long
Dim bDone As Boolean
Dim dTemp As Double

lArrSize = UBound(dGenStack, 2)
lArrDepth = UBound(dGenStack, 1)

Do
    bDone = True
    For i = 0 To lArrSize - 1
        If dGenStack(lSortIdx, i) > dGenStack(lSortIdx, i + 1) Then
'Bubblesort in ascending order
            For j = 0 To lArrDepth
                dTemp = dGenStack(j, i)
                dGenStack(j, i) = dGenStack(j, i + 1)
                dGenStack(j, i + 1) = dTemp
            Next j
            bDone = False
        End If
    Next i
Loop Until bDone

End Sub
```

Lookup Functions

The code makes extensive use of look up functions to turn text input into numerical indices for processing. These routines perform look ups for indices relating to the type of generating unit, the type of fuel, the price of fuel, or the type of electricity generating plant defined by the Florida Department of Environmental Protection.

```
Public Function PlantTypeLookup(sPrimeMover As String, sFuelType As
String) As Integer

Dim i As Long

i = 1

Do
    If Sheet5.Cells(i + 1, 1) = sPrimeMover And Sheet5.Cells(i + 1, 2)
= sFuelType Then Exit Do
    i = i + 1
Loop

PlantTypeLookup = i

End Function

Public Function GetFuelIndex(sFuelType As String) As Long

'Gets the fuel type index from the Inputs sheet

Dim i As Long

i = 2
Do
    If Sheet5.Cells(i, 7) = sFuelType Then Exit Do
    i = i + 1
Loop

GetFuelIndex = i

End Function

Public Function GetFuelPriceIndex(sFuelType As String) As Long

Dim i As Long
Dim bMatch As Boolean

i = 2
```

```
Do
    If Sheet2.Cells(1, i) = sFuelType Then
        bMatch = True
        Exit Do
    End If
    i = i + 1
    If IsEmpty(Sheet2.Cells(1, i)) Then Exit Do
Loop

If bMatch Then
    GetFuelPriceIndex = i
Else
    GetFuelPriceIndex = 0
End If

End Function

Public Function DEPTypeLookup(sDEPType As String) As Integer

Select Case sDEPType
Case "Cogen"
    DEPTypeLookup = 0
Case "WTE"
    DEPTypeLookup = 1
Case "LF"
    DEPTypeLookup = 2
Case "IPP"
    DEPTypeLookup = 3
Case "FMPA"
    DEPTypeLookup = 4
Case "CO-OP"
    DEPTypeLookup = 5
Case "FPL"
    DEPTypeLookup = 6
Case "PE"
    DEPTypeLookup = 7
Case "GP"
    DEPTypeLookup = 8
Case "TECO"
    DEPTypeLookup = 9
Case "WTP"
    DEPTypeLookup = 10
Case "Hydro"
    DEPTypeLookup = 11
Case "New"
    DEPTypeLookup = 12
End Select

End Function
```

Sub SetGenStack

This subroutine is run once for each month of the simulation. Since fuel prices only change monthly, the fuel that each unit utilizes will stay the same for the entire simulation month. This routine checks in service and out of service dates to determine which units are available for the month, and selects the cheapest fuel alternative.

```
Sub SetGenStack(dtCurrDate, dCarbonPrice)

'Sub sets the Gen stack for the particular month, utilizing the
cheapest fuel alternative for each unit

'GenStack description (4xN array):
'Generator ID is element 0
'Generation cost/MWh is element 1
'Generator fuel type index is element 2
'Generator fuel burn/MWh is element 3
'Generator emissions/MWh is element 4

Dim i As Long
Dim j As Long
Dim k As Long
Dim iDateIdx As Integer
Dim dFuelCost As Double
Dim dMinCost As Double
Dim iMinFuel As Integer

iDateIdx = DateDiff("m", Sheet2.Cells(2, 1), dtCurrDate)

j = 0
For i = 0 To lGenCnt
    iMinFuel = 0
    If dtCurrDate >= aGenUnits(i).AvailDate And dtCurrDate <
aGenUnits(i).RetireDate Then
        ReDim Preserve dGenStack(4, j)
        dGenStack(0, j) = i
        If aGenUnits(i).NumFuels > 1 Then
        'Loop through fuel alternatives and pick cheapest
            dMinCost = 1E+30
            For k = 1 To aGenUnits(i).NumFuels
                If aGenUnits(i).Fuel(k - 1).PriceIndex = 0 Then
                    dFuelCost = 0
                Else
                    dFuelCost = Sheet2.Cells(iDateIdx + 2,
aGenUnits(i).Fuel(k - 1).PriceIndex)
                End If
```

```
                dFuelCost = dFuelCost + aGenUnits(i).Fuel(k - 1).Adder
                dGenStack(2, j) = aGenUnits(i).Fuel(k - 1).TypeIndex
                dGenStack(3, j) = aGenUnits(i).HeatRate
                dGenStack(4, j) = aGenUnits(i).DEPCapUnit *
aGenUnits(i).HeatRate * Sheet5.Cells(dGenStack(2, j), 8) *
aGenUnits(i).CCS / 1000
                dGenStack(1, j) = (aGenUnits(i).HeatRate * dFuelCost)
+ aGenUnits(i).VOM + (dGenStack(4, j) * dCarbonPrice)
                If dGenStack(1, j) < dMinCost Then
                    dMinCost = dGenStack(1, j)
                    iMinFuel = k - 1
                End If
            Next k
            If aGenUnits(i).Fuel(iMinFuel).PriceIndex = 0 Then
                dFuelCost = 0
            Else
                dFuelCost = Sheet2.Cells(iDateIdx + 2,
aGenUnits(i).Fuel(iMinFuel).PriceIndex)
            End If
            dFuelCost = dFuelCost + aGenUnits(i).Fuel(iMinFuel).Adder
            dGenStack(2, j) = aGenUnits(i).Fuel(iMinFuel).TypeIndex
            dGenStack(3, j) = aGenUnits(i).HeatRate
            dGenStack(4, j) = aGenUnits(i).DEPCapUnit *
aGenUnits(i).HeatRate * Sheet5.Cells(dGenStack(2, j), 8) / 1000
            dGenStack(1, j) = aGenUnits(i).HeatRate * dFuelCost +
aGenUnits(i).VOM + dGenStack(4, j) * dCarbonPrice
        Else
            If aGenUnits(i).Fuel(0).PriceIndex = 0 Then
                dFuelCost = 0
            Else
                dFuelCost = Sheet2.Cells(iDateIdx + 2,
aGenUnits(i).Fuel(0).PriceIndex)
            End If
            dFuelCost = dFuelCost + aGenUnits(i).Fuel(0).Adder
            dGenStack(2, j) = aGenUnits(i).Fuel(0).TypeIndex
            dGenStack(3, j) = aGenUnits(i).HeatRate
            dGenStack(4, j) = aGenUnits(i).DEPCapUnit *
aGenUnits(i).HeatRate * Sheet5.Cells(dGenStack(2, j), 8) / 1000
            dGenStack(1, j) = aGenUnits(i).HeatRate * dFuelCost +
aGenUnits(i).VOM + dGenStack(4, j) * dCarbonPrice
        End If
        j = j + 1
    End If
Next i

End Sub
```

Sub CompareOutput

This routine was written to compare the model's output with actual data for the purposes of back-casting.

```
Sub CompareOutput()

Dim iSrcRow As Integer
Dim iTgtRow As Integer
Dim iOutRow As Integer
Dim iTemp As Integer
Dim bMatch As Boolean
Dim sPlant As String
Dim dGen As Double

iSrcRow = 2
iOutRow = 3
Do Until IsEmpty(Sheet4.Cells(iSrcRow, 2))
    sPlant = Sheet4.Cells(iSrcRow, 2)
    'Check to see if plant has already been counted
    iTemp = 3
    bMatch = False
    Do Until IsEmpty(Sheet11.Cells(iTemp, 1))
        If sPlant = Sheet11.Cells(iTemp, 1) Then
            bMatch = True
            Exit Do
        End If
        iTemp = iTemp + 1
    Loop
    If Not bMatch Then
        dGen = 0
        iTemp = 2
        Sheet11.Cells(iOutRow, 1) = sPlant
        Do Until IsEmpty(Sheet4.Cells(iTemp, 2))
            If sPlant = Sheet4.Cells(iTemp, 2) Then dGen = dGen +
Sheet4.Cells(iTemp, 6)
            iTemp = iTemp + 1
        Loop
        Sheet11.Cells(iOutRow, 2) = dGen
        dGen = 0
        iTemp = 2
        Do Until IsEmpty(Sheet10.Cells(iTemp, 3))
            If sPlant = Sheet10.Cells(iTemp, 3) Then dGen = dGen +
Sheet10.Cells(iTemp, 5)
            iTemp = iTemp + 1
        Loop
        Sheet11.Cells(iOutRow, 3) = dGen
        iOutRow = iOutRow + 1
    End If
    iSrcRow = iSrcRow + 1
Loop

End Sub
```

Subroutine GrowLoads

This set of routines utilizes a base hourly electric load shape with particular peak demand and total energy demand characteristics, and reshapes it to be consistent with the peak demand and total energy demand forecast used in the simulation, the target characteristics. The routine first shifts the base shape so that its weekdays and weekends conform to the target year. The routine then searches for the shape parameter δ that satisfies:

$$TargetEnergy = \sum_{i=1}^{8760} BaseEnergy_i * \left(\frac{TargetDemand}{BaseDemand}\right) * e^{\delta * \ln \frac{BaseEnergy_i}{BaseDemand}}$$

Note that at the peak hour of the year, the exponential term is equal to 1 and the peak hour simply grows at the same rate as demand. Every other hour of the year is scaled, so that peak demand can grow at 5%, say, and total energy demand can grow at 10%. The load shape will flatten itself out in this case. If total energy grows at less than demand, the load shape will stretch.

```
Sub GrowLoads()

'Only needs to be rerun after changing load forecast
'Deleting all load data but the base year is not required before
running but makes the output cleaner

Dim iBaseYear As Integer
Dim iTargetYear As Integer
Dim i As Long
Dim j As Long
Dim dBaseLoad() As Double
Dim dLoadShape() As Double
Dim lCount As Long
Dim iLength As Integer
Dim iCount As Integer
Dim iDay As Integer
Dim iRow As Integer

Dim dDemand As Double
Dim dEnergy As Double
Dim dDelta As Double
```

```
'Read and format the base shape
lCount = 1
iBaseYear = Year(Sheet3.Cells(lCount, 1))
lCount = DateSerial(iBaseYear + 1, 1, 1) - DateSerial(iBaseYear, 1, 1)
iLength = lCount * 24 - 1
ReDim dBaseLoad(iLength)

iCount = 0
For i = 1 To lCount
    For j = 2 To 25
        dBaseLoad(iCount) = Sheet3.Cells(i, j)
        iCount = iCount + 1
    Next j
Next i

'Read and output grown loads
iRow = 12
lCount = lCount + 1
Do Until IsEmpty(Sheet8.Cells(iRow, 1))
    iTargetYear = Sheet8.Cells(iRow, 1)
    Call ShiftLoadShape(dBaseLoad, dLoadShape, iBaseYear, iTargetYear)
    dDemand = Sheet8.Cells(iRow, 2)
    dEnergy = Sheet8.Cells(iRow, 3) * 1000
    Call GetShapeParm(dLoadShape, dDemand, dEnergy)
    iDay = (UBound(dLoadShape) + 1) / 24
    iCount = 0
    For i = 0 To iDay - 1
        Sheet3.Cells(lCount, 1) = DateSerial(iTargetYear, 1, 1) + i
        For j = 2 To 25
            Sheet3.Cells(lCount, j) = dLoadShape(iCount)
            iCount = iCount + 1
        Next j
        lCount = lCount + 1
    Next i
    iRow = iRow + 1
Loop

End Sub

Sub GetShapeParm(dLoadShape() As Double, dTgtDem As Double, dTgtEng As
Double)

Dim dDelta As Double
Dim iPower As Integer
Dim i As Long
Dim j As Long
Dim iLength As Long
Dim dLoadMax As Double

Const ConvCrit = 1
```

```
iLength = UBound(dLoadShape)
For i = 0 To iLength
    If dLoadShape(i) > dLoadMax Then dLoadMax = dLoadShape(i)
Next i

dDelta = 10
iPower = 2
Do While Abs(dTgtEng - TotalEnergy(dLoadShape(), dLoadMax, dTgtDem,
dDelta)) > ConvCrit
    iPower = iPower - 1
    dDelta = MinValDeviation(dLoadShape(), dLoadMax, dTgtDem, dTgtEng,
dDelta, iPower)
Loop

For i = 0 To iLength
    dLoadShape(i) = dLoadShape(i) * (dTgtDem / dLoadMax) * Exp(dDelta
* Log(dLoadShape(i) / dLoadMax))
Next i

End Sub

Function MinValDeviation(dLoadShape() As Double, ByVal dLoadMax As
Double, ByVal dTgtDem As Double, ByVal dTgtEng, ByVal dDelta As
Double, iPower As Integer) As Double

Dim dInitDev As Double
Dim dLastDev As Double
Dim dDev As Double
Dim dWorkDelta As Double

dInitDev = dTgtEng - TotalEnergy(dLoadShape(), dLoadMax, dTgtDem,
dDelta)
dDev = dInitDev
dWorkDelta = dDelta

Do While Sgn(dInitDev) = Sgn(dDev)
    dLastDev = dDev
    dWorkDelta = dWorkDelta - Sgn(dInitDev) * 10 ^ iPower
    dDev = dTgtEng - TotalEnergy(dLoadShape(), dLoadMax, dTgtDem,
dWorkDelta)
Loop

If Abs(dLastDev) < Abs(dDev) Then
    MinValDeviation = dWorkDelta + Sgn(dInitDev) * 10 ^ iPower
Else
    MinValDeviation = dWorkDelta
End If

End Function
```

```
Function TotalEnergy(dLoadShape() As Double, ByVal dLoadMax As Double,
ByVal dTgtDem As Double, ByVal dDelta As Double) As Double

Dim i As Integer
Dim dTempSum As Double
Dim iLength As Integer

iLength = UBound(dLoadShape)

For i = 0 To iLength
    dTempSum = dTempSum + dLoadShape(i) * (dTgtDem / dLoadMax) *
Exp(dDelta * Log(dLoadShape(i) / dLoadMax))
Next i

TotalEnergy = dTempSum

End Function

Sub ShiftLoadShape(dBaseLoadShape() As Double, dTargetLoadShape() As
Double, iBaseYear As Integer, iTargetYear As Integer)

Dim dtStartBase As Date
Dim dtStartTarget As Date
Dim iDateOffset As Integer
Dim iBaseLength As Integer
Dim iTargetLength As Integer
Dim i As Long
Dim iCount As Integer

dtStartBase = DateSerial(iBaseYear, 1, 1)
dtStartTarget = DateSerial(iTargetYear, 1, 1)

iBaseLength = UBound(dBaseLoadShape)
iTargetLength = (DateSerial(iTargetYear + 1, 1, 1) -
DateSerial(iTargetYear, 1, 1)) * 24 - 1

ReDim dTargetLoadShape(iTargetLength)

iDateOffset = Weekday(dtStartTarget) - Weekday(dtStartBase)
If iDateOffset > 3 Then iDateOffset = iDateOffset - 7
If iDateOffset < -3 Then iDateOffset = iDateOffset + 7

Select Case iDateOffset
Case 0
    iCount = 0
Case Is > 0
    iCount = iDateOffset * 24
Case Is < 0
    iCount = iBaseLength + 1 - iDateOffset * 24
End Select

For i = 0 To iTargetLength
```

```
    If iCount > iBaseLength Then iCount = iCount - iBaseLength - 1
    dTargetLoadShape(i) = dBaseLoadShape(iCount)
    iCount = iCount + 1
Next i

End Sub

Sub test()

Dim i As Long
Dim j As Long

Dim iLoadShapeIdx As Integer

Dim dLoadShape(8759) As Double
Dim dTemp As Double
Dim dDemand As Double
Dim dEnergy As Double
Dim bEcon As Boolean

bEcon = Not Range("CheckBoxStatus")

dDemand = 49391 * 1.1
dEnergy = 246492002 * 1.05

iLoadShapeIdx = 0

For i = 1 To 365
    For j = 2 To 25
        dLoadShape(iLoadShapeIdx) = Sheet3.Cells(i, j)
        iLoadShapeIdx = iLoadShapeIdx + 1
    Next j
Next i



End Sub
```

Subroutine DefineNewPlant

This routine defines the new plant that will be built by the simulation, if a new plant is necessary for reliability purposes. The new plant can either be determined endogenously, by least cost, or exogenously based on a user supplied configuration.

```
Private Sub DefineNewPlant(NewPlant() As GenPlant, dCarbonPrice As
Double)

Dim dLeastCost As Double
Dim lLeastCostUnitID As Long
Dim lFuelIndex As Long
Dim dEmissionsCost As Double
Dim dTotalCost As Double
Dim bEconomic As Boolean
Dim bDone As Boolean
Dim lArrSize As Long
Dim tmpPlant As GenPlant

Dim i As Long
Dim j As Long

bEconomic = Not Range("CheckBoxStatus")

If bEconomic Then
    j = 0
    dLeastCost = 1E+30

    i = 2
    Do Until IsEmpty(Sheet5.Cells(i, 13))
        ReDim Preserve NewPlant(j)
        lFuelIndex = GetFuelIndex(Sheet5.Cells(i, 20))
        dEmissionsCost = Sheet5.Cells(i, 21) *
Sheet5.Cells(lFuelIndex, 8) * dCarbonPrice / 1000
        dTotalCost = dEmissionsCost + Sheet5.Cells(i, 19)
        NewPlant(j).AvailPct = Sheet5.Cells(i, 14)
        NewPlant(j).PlantName = Sheet5.Cells(i, 13)
        NewPlant(j).SumCap = 1000
        NewPlant(j).WinCap = 1000
        NewPlant(j).DEPCapUnit = 1
        NewPlant(j).DEPTypeCode = "New"
        NewPlant(j).HeatRate = Sheet5.Cells(i, 21)
        NewPlant(j).NumFuels = 1
        ReDim NewPlant(j).Fuel(0)
        NewPlant(j).Fuel(0).Type = Sheet5.Cells(i, 20)
        NewPlant(j).Fuel(0).TypeIndex =
GetFuelIndex(NewPlant(j).Fuel(0).Type)
        NewPlant(j).Fuel(0).PriceIndex = 0
        NewPlant(j).VOM = dTotalCost - Sheet5.Cells(i, 15)
```

```
        NewPlant(j).LevelCost = dTotalCost
        NewPlant(j).CCS = Sheet5.Cells(i, 24)
        NewPlant(j).FixedCost = Sheet5.Cells(i, 25) *
NewPlant(j).SumCap
        i = i + 1
        j = j + 1
    Loop

    lArrSize = UBound(NewPlant)
    Do
        bDone = True
        For i = 0 To lArrSize - 1
            If NewPlant(i).LevelCost > NewPlant(i + 1).LevelCost Then
'Bubblesort in ascending order
                tmpPlant = NewPlant(i)
                NewPlant(i) = NewPlant(i + 1)
                NewPlant(i + 1) = tmpPlant
                bDone = False
            End If
        Next i
    Loop Until bDone


Else

    i = 2
    j = 0
    Do Until IsEmpty(Sheet5.Cells(i, 13))
        If Sheet12.Cells(i + 3, 2) > 0 Then
            ReDim Preserve NewPlant(j)
            lFuelIndex = GetFuelIndex(Sheet5.Cells(i, 20))
            dEmissionsCost = Sheet5.Cells(i, 21) *
Sheet5.Cells(lFuelIndex, 8) * dCarbonPrice / 1000
            dTotalCost = dEmissionsCost + Sheet5.Cells(i, 19)
            NewPlant(j).AvailPct = Sheet5.Cells(i, 14)
            NewPlant(j).PlantName = Sheet5.Cells(i, 13)
            NewPlant(j).SumCap = 1000 * Sheet12.Cells(i + 3, 2)
            NewPlant(j).WinCap = 1000 * Sheet12.Cells(i + 3, 2)
            NewPlant(j).DEPCapUnit = 1
            NewPlant(j).DEPTypeCode = "New"
            NewPlant(j).HeatRate = Sheet5.Cells(i, 21)
            NewPlant(j).NumFuels = 1
            ReDim NewPlant(j).Fuel(0)
            NewPlant(j).Fuel(0).Type = Sheet5.Cells(i, 20)
            NewPlant(j).Fuel(0).TypeIndex =
GetFuelIndex(NewPlant(j).Fuel(0).Type)
            NewPlant(j).Fuel(0).PriceIndex = 0
            NewPlant(j).VOM = dTotalCost - Sheet5.Cells(i, 15)
            NewPlant(j).LevelCost = dTotalCost
            NewPlant(j).CCS = Sheet5.Cells(i, 24)
            NewPlant(j).FixedCost = Sheet5.Cells(i, 25) *
NewPlant(j).SumCap
```

```
            j = j + 1
        End If
        i = i + 1
    Loop

End If

End Sub

Public Function PriceNewPlant(NewPlant() As GenPlant)

Dim i As Long
Dim j As Long

Dim lArrSize As Long
Dim dTemp As Double

lArrSize = UBound(NewPlant)

If Not Range("CheckBoxStatus") Then
    j = 0
Else
    j = lArrSize
End If

For i = 0 To j
    dTemp = dTemp + NewPlant(i).SumCap / 1000 * NewPlant(i).LevelCost
Next i

PriceNewPlant = dTemp

End Function
```

Subroutine AddGenStack

The generation stack utilized in the program is a complicated data element, and this routine is used to add generating units to the stack. It is called whenever a new plant is built endogenously.

```
Sub AddGenStack(dGenStack() As Double, NewPlant As GenPlant,
PlantIndex As Long)

Dim lArrSize As Long

lArrSize = UBound(dGenStack, 2) + 1

ReDim Preserve dGenStack(4, lArrSize)

dGenStack(0, lArrSize) = PlantIndex
dGenStack(2, lArrSize) = NewPlant.Fuel(0).TypeIndex
dGenStack(3, lArrSize) = NewPlant.HeatRate
dGenStack(4, lArrSize) = NewPlant.DEPCapUnit * NewPlant.HeatRate *
Sheet5.Cells(dGenStack(2, lArrSize), 8) / 1000
dGenStack(1, lArrSize) = NewPlant.LevelCost

End Sub

Sub RetrofitCCS(aGenUnits() As GenPlant, dCCSCost As Double, dCCSPct
As Double, dCarbonPrice As Double)

'Processes the generation stack

End Sub
```

Output Routines

The code utilizes a number of routines that write output to flat files for post processing and diagnostic purposes. These routines write the hourly loads used in the simulation, the fuel prices, and the characteristics of the generating units that exist at the beginning of the simulation.

```
Sub WriteInputLoad(sDir As String)

Dim sOutfile As String
Dim sLine As String
Dim i As Long
Dim j As Long

sOutfile = "Input_Load.csv"

Open sDir & sOutfile For Output As #1

i = 1

Do Until IsEmpty(Sheet3.Cells(i, 1))
    sLine = Sheet3.Cells(i, 1)
    For j = 2 To 25
        sLine = sLine & "," & Sheet3.Cells(i, j)
    Next j
    Print #1, sLine
    i = i + 1
Loop

Close #1

End Sub

Sub WriteInputFuelPrice(sDir As String)

Dim sOutfile As String
Dim sLine As String
Dim i As Long
Dim j As Long

sOutfile = "Input_FuelPrice.csv"

Open sDir & sOutfile For Output As #1

i = 1

Do Until IsEmpty(Sheet2.Cells(i, 1))
    sLine = Sheet2.Cells(i, 1)
    For j = 2 To 28
```

```
        sLine = sLine & "," & Sheet2.Cells(i, j)
    Next j
    Print #1, sLine
    i = i + 1
Loop

Close #1

End Sub

Sub WriteInputGenUnits(sDir As String)

Dim sOutfile As String
Dim sLine As String
Dim i As Long
Dim j As Long

sOutfile = "Input_GenUnits.csv"

Open sDir & sOutfile For Output As #1

i = 1

Do Until IsEmpty(Sheet1.Cells(i, 1))
    sLine = Sheet1.Cells(i, 1)
    For j = 2 To 23
        sLine = sLine & "," & Sheet1.Cells(i, j)
    Next j
    Print #1, sLine
    i = i + 1
Loop

Close #1

End Sub
```

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BIOGRAPHICAL SKETCH

Ted Kury is director of Energy Studies for the Public Utility Research Center (PURC) at the University of Florida. He is responsible for promoting research and outreach activities in energy regulation and policy. He develops research strategies that inform the academic community and practitioners on emerging issues and best practices and serves as an expert resource for regulatory professionals, policymakers, and service providers in Florida and around the world.

Mr. Kury conducts interdisciplinary research related to Florida's energy and climate change policies and serves on the steering committee of UF's Florida Institute for Sustainable Energy. He also collaborates with faculty at other universities around the state as part of the Florida Energy Systems Consortium, a consortium recently created by the governor to leverage the expertise of Florida's research community. In addition, Mr. Kury assists in the coordination of Florida's hurricane hardening efforts.

In collaboration with the World Bank staff, he designs curriculum and leads sessions of the PURC/World Bank International Training Program on Utility Regulation and Strategy. He also develops advanced courses and customized training courses in energy regulation.

Previously, Mr. Kury was a senior structuring and pricing analyst at The Energy Authority in Jacksonville, Florida where he developed proprietary models relating to the management of system-wide cash flows at risk, including the quantification of portfolio risk related to both physical utility and financial assets. He also built custom software packages to quantify cross commodity risk, asset valuation, and optimization of natural gas storage with dynamic programming.

Mr. Kury began his career in energy as a senior economist at SVBK Consulting Group in Orlando, Florida. Some of his duties included participating in legal proceedings relating to the deregulation of electric markets and establishment of tariffs and helping municipal electric, natural gas, and water/wastewater utilities develop retail rates.

Mr. Kury earned M.A. and B.A. degrees in economics from the State University of New York at Buffalo, and his Ph. D. in economics from the University of Florida in 2013.