UNDERSTANDING FUEL DIVERSITY TRADE-OFFS AND RISKS: MAKING DECISIONS FOR THE FUTURE

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Introduction

For almost two decades during the 1980s and 1990s we operated in world of secure fuel supplies, stable or declining prices of primary fuels, and somewhat more predictable environmental policy. The past six to eight years have introduced a reversal of past trends: natural gas and petroleum prices have increased and become more volatile; hurricanes and geopolitical forces have disrupted energy supplies; increasingly stringent, and often uncertain enforcement of, environmental regulations have contributed to higher costs to electric utilities; and questions about climate change policies remain unresolved. These factors have introduced more uncertainty into utility planning for new generating capacity and consequently greater risk for investors, consumers, and regulators.

Although the world has changed, Florida's electric utilities are still expected to meet the energy needs of their expanding customer bases as cleanly, reliably, safely, and cost-effectively as they previously had. However, these objectives are inherently difficult to reconcile. As John Holdren, Professor of Environmental Policy at Harvard University observed:

> The desire to limit costs is often at odds with the aims of increasing reliability, reducing vulnerability, and improving environmental performance. The historically low costs of oil, natural gas, and many hydropower projects are not likely to be matched by the more abundant fossil, nuclear, and renewable alternatives. Expanding domestic oil production in order to limit imports eventually encounters not only rising marginal costs but also rising opposition when the remaining domestic resources lie under fragile or particularly highly prized environments. Replacing conventional oil and gas with synthetic liquids and gases made from tar sands, oil shales, and coal will sharply increase the emissions of climate-altering carbon dioxide unless costly carbon capture and sequestration accompany these conversions. Rapid expansion of nuclear energy may risk outrunning the capabilities of national and international organizations to manage its risks. And so on.[1]

In this essay, we provide a policy context for the planning process by examining several major issues that enter into the electric utility calculus for building additional capacity. We also refer to the uncertainty and risk that surround investment options where the objectives of cost efficiency, reliability, environmental protection, and safety sometimes appear to conflict.

Uncertainty and the Risk Calculus for Capacity Expansion

Decisions on capacity expansion are a function of multiple factors. On the demand-side, consideration must be given to demand forecasts for total and peak usage which are a function of population projections, the location of projected population growth, and projected economic activity. Unfortunately, forecasts are never perfectly accurate, and forecast deviations may have major risk implications for shareholders and consumers who could bear some of the cost in the long term for a utility's excess or insufficient capacity and for regulators whose appointments are politically determined. In this vein, we discuss population projections and load forecasts as being one piece of the capacity expansion puzzle.

On the supply-side, more than the amount of generating capacity must be considered. The choice of fuel and generating technology combinations are a function of several factors: projected peak and base-load demand growth, fuel price and availability forecasts, expected environmental compliance costs, technology reliability, and the potential for energy efficiency and demand-side management (DSM) to reduce peak and base-load demand growth.

With respect to fuel prices and availability, oil and natural gas have become increasingly volatile in recent years relative to the other competing fossil fuel, coal. Florida was dependent on these fuels for just over 52 percent of its power generation and almost 70 percent of installed capacity in 2004.[2] The dominance of gas and oil has led to calls for fuel diversification: coal, nuclear power, energy efficiency, and DSM. However, with respect to potential environmental compliance costs from potential climate change policy, some diversification strategies may appear better than others. Complicating expansion decisions are the long lead times required to construct coal-fired plants (7 years on average) and nuclear plants (10 years as an estimate). While these decisions *ex ante* may appear to be sound decisions, at the time of commercial operation, *ex post*, they may appear to be poor decisions due to realizations of uncertainties during plant construction in fuel markets and environmental policy. Consequently, because these plants are long-lived assets, decisions made today will have effects for 20 years and more since recovery of power plant capital costs as well as fuel costs and their associated risks must be borne either by ratepayers or utility shareholders.

Energy efficiency and DSM arguably provide another, possibly lower cost, alternative to meeting future energy needs through demand reductions. However, even these programs have associated uncertainties in that consumers may not respond to them as envisioned and demand may not be reduced at all or very little.[3] If that is the case, Florida's utilities may not have the necessary generating capacity needed at peak and their customers may have to pay potentially higher prices for the peak power that is available. Regulators also may experience a political backlash if shortfalls in energy supply result from those strategies.

In the next section we discuss the dimensions of uncertainty that can help utilities, regulators, policy makers, and other interested stakeholders better understand the complexity of the utility planning process.

Categories and Dimensions of Uncertainties and Risk

Categorization of Uncertainties Confronting Utility Planners

In its Report on Clean Coal Generation, Florida Power & Light (FPL) identified five areas of uncertainty that could influence the decision to build a coal-fired power plant: fuel price differential, fuel transportation costs, environmental compliance costs, licensing requirements, and capital costs. We use the categories defined by FPL as a template to define, in slightly more general terms, the categories of uncertainties that are likely to be considered in most electric utilities' planning efforts for capacity expansion and fuel diversification:

1) Fuel price and availability;
2) Siting and permitting;
3) Capital costs and technology; and
4) Environmental compliance and policy.

Our discussion of these four categories relates primarily to supply-side technologies using coal, natural gas, oil, nuclear power, and renewable resources which are likely to affect capacity most in the next ten years. Our discussion also relates strategies of energy efficiency and demand-side management (DSM) resources to these fuel sources.

Dimensions of Uncertainty

Uncertainty has different time dimensions which are likely to be quite important and to be implicitly considered in utility planning processes.

1) <u>One time, up front uncertainty:</u> This type of uncertainty occurs at or before commercial operation of a new facility and is a one time realization. One example is a cost overrun. Once the realization associated with the uncertainty occurs the uncertainty is over.
2) <u>One time, future uncertainty:</u> The realization of this outcome occurs at some point in the future after a decision has been made and after commencement of commercial operation of a new facility. An example is the course of future climate change policy, if there is any. Once the realization associated with the uncertainty occurs the uncertainty is over.
3) <u>Ongoing uncertainty (short-term and long-term):</u> Uncertain outcomes are continually realized over time such as with fuel prices and fuel availability in the long-term or technology reliability in the short or long-term.

Controllability of Risk Associated with Uncertainty

An electric utility can control the financial risks associated with some types of uncertainty by either owning the asset itself or financially controlling an asset, such as through hedging or contracts. Consumers may be able to mitigate the uncertainty and associated risks of price increases through energy efficiency measures or participation in DSM programs. However, as discussed below, a utility or its consumers cannot control every facet of planning capacity expansion. To the extent that these things cannot be

controlled, the financial risk associated with those uncertainties is borne either by investors or the utility's customers. The allocation of risk is determined by regulators who may face inherent political repercussions from their decisions.

Florida Now and in 2015

Florida's Population and Potential Energy Demand Currently and in 2015[4]

A large factor in forecasting energy demand is the forecast of population growth. Other factors to consider in meeting increased demand are the customer classes that will be driving the growth (residential, commercial, and industrial), and the location of growing demand. If population forecasts are overestimated and demand in their service areas is less than expected, utilities run the risk of building too much capacity, thus shouldering customers with higher rates than necessary or burdening shareholders if part of their investment is disallowed. Conversely, if they underestimate the amount of capacity needed to meet demand, they might be forced to purchase energy in the wholesale market, thus exposing their customers to price uncertainty and potential volatility and their shareholders to possible disallowances.

Between 1990 and 2000, Florida's population grew from 13 million to almost 16 million people, a 23.5 percent increase. The estimated population in 2005 of almost 18 million is concentrated in Central and South Florida. Florida's population is forecast to range from 19.9 million to 22.5 million in 2015.[5] According to the Energy Information Administration (hereafter, EIA), Florida and the states represented by the SERC Reliability Corporation (SERC) are expected to account for the largest amount of new capacity in the nation by 2030.[6] In large part, the southeast's, particularly Florida's, projected population growth is driving that demand. Nationwide, the largest increase in demand from now until 2030 is expected to be in the commercial sector, which will be propelled by continued economic growth of service industries, also a driving force in Florida's economy. By 2015 the growth in demand nationwide will be fairly evenly split between residential and commercial customers with industrial growth lagging behind and pretty flat.[7] These projections are consistent with the past 15 years in Florida where commercial growth has slightly outpaced residential growth and the shares of consumption are converging.[8]

Florida's Generating Capacity Now and in 2015

Florida's electric power is generated predominantly by electric utilities—5 investor-owned electric utilities, 33 municipally-owned electric utilities, and 18 rural electric cooperatives. In 2004, utilities accounted for almost 89 percent of all generated power. Independent Power Producers (IPPs) accounted for the other 11 percent of generated power, an increase of 5 percent over 1990. However, IPP-generated power is proportionately far less in Florida than in the nation as a whole where it provided almost 37 percent in 2004, mostly from natural gas and coal sources.[9]

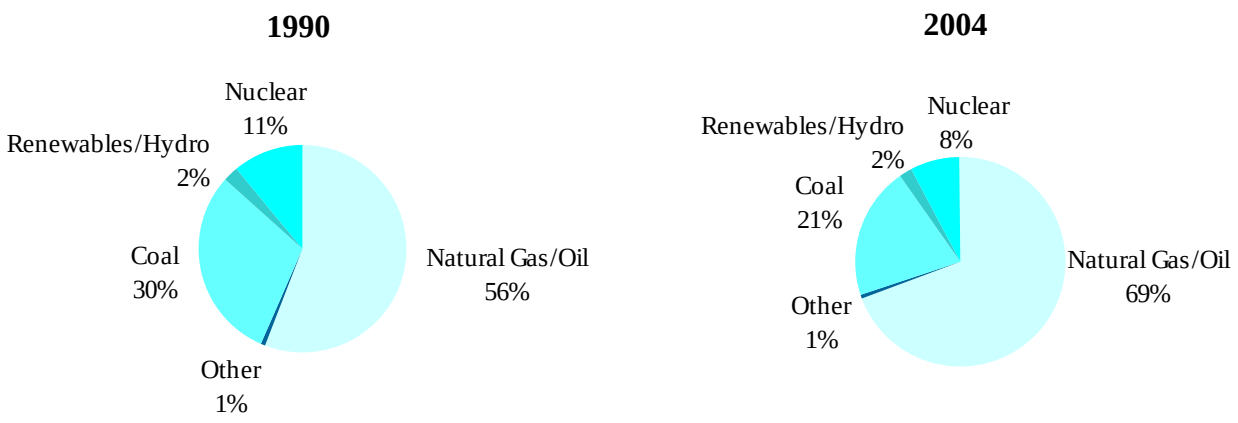
In 2004, Florida ranked second in the country behind Texas in net generation and third in total retail sales behind Texas and California.[10] Florida's electric utilities added an average of 900 megawatts (MW) of new generating capacity per year over the past ten

years. Additional capacity is expected to average 1,500 megawatts per year over the next ten years to accommodate greater demand, replace capacity of retired plants, and replace energy from expired long-term purchased power contracts.[11]

Florida is weakly interconnected with the rest of the US with only 3,600 MW of import capability representing less than 10 percent of peak demand and 2,000 MW of summer and 2,700 MW of winter export capability.[12] Of the 3,600 MW import capability, 2,500 MW are allocated for firm sales and delivery of energy from capacity from generating units co-owned by Florida utilities in Southern Company's service territory and the remaining 1,100 MW can be used for non-firm transactions.

Florida's aggregate capacity resource mix shifted from 1990 to 2004. Natural gas and oil fired capacity increased from 55.9 percent of total generation in 1990 to almost 69.2 percent in 2004; over 90 percent of new generating capacity constructed in Florida was natural-gas fired during that period. The share of generation coming from oil and natural gas fired capacity also increased from 33.6 percent in 1990 to 52.2 percent in 2004. The proportion of coal-fired capacity declined from 29.9 percent in 1990 to 20.6 percent in 2004 as did coal's share of generation declining from 45.7 percent in 1990 to 29.7 percent in 2004. Nuclear power's share of overall generating capacity declined from 11.2 percent in 1990 to 7.7 percent in 2004 and its share of generation fell from 16.6 percent in 1990 to 14.3 percent in 2004.[13]

Florida's Generating Capacity



Florida's utilities are required to submit annual ten-year site plans to explain how they intend to manage projected growth over that time period. In their 2005 forecast for the state's aggregate energy generation mix in 2014, the reporting utilities seem to envision the percentages of coal and natural gas relative to other fuels for generation increasing, and the percentage of nuclear, at least in the next few years, decreasing. Several coal plants are planned, but not projected to come on line until 2012 and 2013.[14]

Florida's electric utilities (not including IPPs, non-utility generators, or imports from outside the state), at least in the most recently available forecasts included in their

2005 Ten-Year Site Plans, project 2014 electricity generation shares to be: over 44 percent of generating capacity from natural gas (up from almost 30 percent in 2004), almost 31 percent from coal (up from 29 percent), 10 percent from nuclear power (down from 13 percent), and 7 percent from oil (down from 12 percent). A smaller portion of total capacity is projected to come from IPPs and renewable resources.[15]

Fuel Prices and Availability

Overview of Fuel Price Trends and Differentials

Fuel costs are a significant component of electricity production costs, and are forecast to account for about 70 percent of generating costs for new natural gas-fired plants, 27 percent for new coal-fired units, and 11 percent for new nuclear power plants in 2015 according to EIA's Annual Energy Outlook (AEO) 2006. An uncertainty for electric utility planning efforts is the extent to which assumptions (EIA's or others) for these cost elements are reliable going forward, particularly because new coal and nuclear plants experience such a long lead time from planning to actual operation. Unfortunately, despite sophisticated models and a 30-year forecasting history, EIA's ability to forecast fuel prices is not too robust. EIA's price forecasts have an absolute average percentage error of around 60 percent for world oil prices, 70 percent for natural gas well head prices, and around 50 percent for coal prices. [16]

Table 1

Levelized Cost Comparison for New Generating Capacity in the United States
2004 dollars per megawatthour

Cost Element	Coal	Natural Gas	Wind	Nuclear
Capital	30.4	11.4	40.7	42.7
Fixed O&M	4.7	1.4	8.3	7.8
Fuel and Variable O&M	14.5	36.9	0	6.6
Total[a]	53.1	52.5	55.8	59.3

[a]includes transmission hookup

O&M = operations and maintenance
Source: EIA, International Energy Outlook 2006, at p.66; available at: http://www.eia.doe.gov/oiaf/ieo/pdf/electricity.pdf.

Table 1 shows the trade-off between capital costs and fuel costs and operation and maintenance (O&M) costs. Natural gas plants are typically the least expensive to build and have lower O&M costs, but have higher fuel costs driven by the price of natural gas relative to coal and nuclear fuel prices. Coal and nuclear plants are more expensive to build, operate, and maintain but their associated fuel costs are lower and their fuel prices have been historically much less volatile. Therefore, electric utilities always face trade-offs between projected capital costs, O&M costs, and fuel costs.

During the years 1996-2005, the average delivered price for coal to U.S. generators was stable relative to the average delivered price of natural gas and oil, as shown in Table 2. The uncertainty for capacity planning, of course, lies in the reliability of forecasts for fuel prices. The assumptions underlying fuel price projections are important because if they turn out to be inaccurate, utilities may opt for energy resources that appear to be *ex ante* cost-effective, but *ex post* are not. Regulators might decide to disallow some of those costs, thereby saddling shareholders or consumers, or both, with the risk of suboptimal technology and fuel choices.

Table 2

Average Cost of Fossil Fuels Delivered To Steam-Electric Utility Plants, 1996-2005

$ per million Btu consumed

Year	Coal	Residual Oil[a]	Natural Gas	All Fossil Fuels[b]
2005	$1.54	$7.12	$8.20	$3.21
2004	1.36	4.73	5.96	2.48
2003	1.27	4.66	5.39	2.23
2002	1.25	3.73	3.56	1.84
2001	1.23	3.73	4.49	1.73
2000	1.20	4.29	4.30	1.74
1999	1.22	2.44	2.57	1.44
1998	1.25	2.08	2.38	1.44
1997	1.27	2.79	2.76	1.52
1996	1.29	3.03	2.64	1.52

[a] Includes fuel oils No. 4, 5, and 6 and topped crude fuel oil.

[b] The weighted average price for all fossil fuels includes both residual fuel oil and light oil (fuel oil No. 2, kerosene, and jet oil), as well as small quantities of coke oven gas, refinery gas, and blast furnace gas.

Source: EIA; reproduced from Standard & Poors, Industry Surveys: Electric Utilities, August 10, 2006, at. P. 15.

Table 3 shows EIA price projections for the fossil fuels from 2004 through 2030. These projections clearly show the fuel cost differential between oil and natural gas prices, on the one hand, and coal prices, on the other hand, widening over time. Based on those projections, the EIA predicts that electric utilities and other providers will rely proportionately more on coal and renewable energy and proportionately less on natural gas for their aggregate generation supply in future years.

The EIA's annual energy supply and demand projections in its AEO reports are based on what happens under well-defined, but restrictive, scenarios using the National

Energy Modeling System (NEMS). Unfortunately, severe weather, economic cycles, and other supply disruptions are not accounted for in the long-term price forecasts; yet such volatility contributes to uncertainty in planning and has real impacts on energy markets.

Table 3

Energy Prices to Electric Power
2004 dollars per million Btu

Fuel Type	2004	2010	2020	2030
Fossil Fuel Average	$2.46	$2.41	$2.46	$2.49
Petroleum Products	5.43	6.5	6.91	7.61
Distillate Fuel	9.23	9.04	9.62	10.28
Residual Fuel	4.76	5.7	6.02	6.73
Natural Gas	5.92	5.46	5.4	6.26
Steam Coal	1.36	1.48	1.39	1.51

Source: EIA, Annual Energy Outlook 2006, Table B3, p. 169.
Prices are the reference case prices used in the AEO.

Natural Gas and Oil

Delivered prices of natural gas to electricity generators were relatively low and stable during the mid-1980s and 1990s. More recently, the average price of natural gas has been increasing.[17] Moreover, prices have exhibited greater volatility, with price increases of over 67 percent from 1999 to 2000, and increases in the delivered price of natural gas of 37 percent from 2004 to 2005. Such volatility can be caused by seasonal demand spikes as was the case in 2000, or from the much publicized supply disruptions due to Hurricanes Ivan, Katrina, and Rita during 2004-05. Since 2000, prices have been higher in large part because U.S. natural gas production has been relatively flat or declining in the past six years. Moreover, the gas being brought to market is increasingly drawn from nontraditional sources that are typically more costly to extract. At the same time, a dramatic expansion in gas-fired combined-cycle capacity and economic growth contributed to pressure on historical supply and storage patterns which have effects on the price. Natural gas imports from Canada and other countries have increased. Incremental imports from outside North America will be more expensive as they will be in the form of LNG.[18] However, despite their relatively higher costs, LNG prices have been steadily declining in recent years. For example, investment in LNG (liquification, shipping, and regasification) per unit of output has decreased from more than $4.50 per million Btu in the early 1990s to approximately $3.00 per million Btu ($2004).[19]

Long-term contracting of natural gas is either difficult or not possible as there is uncertainty regarding the total amount of gas needed at any one time and there are often storage problems. Long-term contracting may not be considered desirable due to the premiums required to guarantee a fixed price and the high costs associated with financial hedging of the price. Still, electricity generators can engage in short-term contracting as evidenced by the 50 percent increase in the delivered price of natural gas from 2003-2005, compared to the over 100 percent increase in spot prices during that time period.[20]

Exemplifying the increased volatility in natural gas price, the Henry Hub spot

prices declined by about 28 percent between August 2005 and August 2006. This decrease reflects a lack of supply disruptions due to weather events and a higher level of working gas in storage. Spot prices have been increasing in recent weeks with the advent of autumn. Nonetheless, the Henry Hub spot price is still 60 percent lower than it was in the aftermath of Hurricane Rita last October.[21]

Reliance on spot markets and short-term contracting prices means that electric utilities are hard pressed to reduce or control for uncertainty in future fuel prices. The only other option, and not an easy one to implement, is to try to hedge their risk physically, either by owning gas reserves or contracting gas storage if they own gas-fired plants.[22] Still, the duration of contracts for transportation and for the commodity itself is likely to diminish in future years.[23] The consequence of shorter contract durations is increased price uncertainty and higher risk for the foreseeable future.

Pipeline transportation of gas in the southeast generally has not been a concern except at peak usage times or during supply disruptions that also affect pipeline availability. Pipeline expansion projects have been ongoing during the period of 2000-2005 to meet increased demand in the region. Capacity is expected to expand significantly in the region in 2007 and 2008. According to the EIA, this projected growth depends on the completion of several large-scale conventional storage sites, the implementation of at least three proposed LNG import facilities in the region, and the continued development of gas-fired power generation in the region, particularly in Florida.[24]

The 1980s and 1990s were relatively stable in terms of oil supply and low prices. We need only recall the oil crises in 1973 and 1979 to understand the inherent volatility due to political events. Rapidly increasing world demand for petroleum with the possibility of politically motivated disruptions exposes Florida utilities more than utilities in many other regions to volatility because Florida relies on residual fuel oil for 12 percent of its electricity generating capacity. Prices for sales to end users, including the electric power industry, have been particularly volatile compared to prices for other energy sources and have soared from an average price of almost $.074 per gallon ($4.73 per million Btu) in 2004 to almost $1.05 per gallon ($7.12 per million Btu) in 2005.[25]

According to the FPSC, Florida's electric utilities continued to forecast declining natural gas prices until 2007, with gradual price increases thereafter. The FPSC expressed skepticism about those forecasts because they have been historically well below actual natural gas prices.[26] As a recent report by the Brattle Group points out, various forecasts about long-term prices of delivered natural gas show prices dipping from 2005 levels during the next ten years with little consensus as to how steadily they will decline. For example, AEO 2006 and Global Insight Inc. predict steady declines but Energy and Environmental Analysis, Inc. projects prices to remain at higher absolute levels. The uncertainty surrounding long-term pricing relates to long-term structural market issues, according to the Brattle Group, such as the amount and price of LNG imports.[27] EIA also projects oil prices to increase steadily after 2010 under its reference case scenario but other forecasts vary significantly, reflecting the great uncertainty about future oil prices.[28]

Coal

Coal is the most abundant of fossil fuels in the world and its reserves are the most widely distributed, with 26 percent of those reserves located in the U.S.[29] Coal production in the U.S. has remained around 1,100 million tons annually since 1996, but is projected to reach 1,272 million tons in 2015 to accommodate growing generation demand from coal-fired plants.[30] Coal prices to U.S. generators decreased steadily throughout the 1990s, but have been steadily increasing on average each year since 2000, most recently by 13 percent from an average of $27.42 per short ton ($1.36 per million Btu) in 2004 to an average of $30.91 per short ton ($1.52 per million Btu) through November 2005. Coal stocks have been declining since 2003 for electricity generation, in response to increasing demand and as a result of transportation problems (see below).[31]

The prices for coal delivered to electric utilities have been much more stable in the past ten years than the average prices for natural gas or oil although all three primary fuels – coal, natural gas, and oil -- have been increasing in average price. One reason for the greater stability in and lower uncertainty with coal prices is that coal tends to be purchased on 3-5 year contracts, longer terms than for purchases of natural gas and, to a lesser extent, than for natural gas or oil on the spot market.

Coal purchased on the spot market typically supplements long-term coal contracts. As a growing number of long-term contracts for delivered coal begin to expire, the greater exposure to spot market prices will likely translate into higher fuel prices for coal generation.[32] Spot prices have already experienced volatility, in part because of structural changes in the industry. According to one analysis, the top ten coal producers controlled 64 percent of national coal production in 2003, compared to 36 percent in 1989, thus accelerating the elimination of excess capacity. Moreover, due to new mining technologies, capacity has been added less frequently and in greater increments when it is.[33] Spot prices for coal in all production regions have increased in recent years. For example, spot prices for coal in the Central Appalachian region increased from less than $35 in September 2003 to almost $50 in September 2006.[34] An uncertainty going forward will be the extent to which electric power providers can continue to enter into multi-year contracts that have historically protected coal purchases from the price volatility of the spot market. The delivered price of coal in 2015 is expected to hover around $1.40 per million Btu in 2015. [35]

On average, 40 percent of the price of delivered coal to electric utilities is due to transportation costs.[36] According to the FPSC, utilities that can use rail and/or barge options have historically enjoyed lower prices than those that relied on a single transportation mode. The FPSC notes that infrastructure expansions for rail facilities and shipping ports may be required if Florida's utilities expect to build more coal-fired plants.[37] In fact, FPL's analysis of the viability of adding clean coal generation to its generation portfolio concluded that "without competitively priced fuel transportation it is very unlikely that clean coal generation would be a cost-effective choice."[38] From 1979-2001, average domestic coal transport rates fell steadily in real dollars per ton from $13.36 to $9.01,[39] but transportation rates have recently been increasing due to increased fuel costs driven by petroleum prices.[40] This decreasing trend was due to infrastructure investments and resulting overcapacity, in addition to consolidation of the railroad industry. According to the EIA, there will be greater demands on rail infrastructure but an expectation of incremental investments.[41] However, while railroad consolidation has

resulted in greater efficiencies, it also has left the rail industry with six major operators that have been eliminating rail routes and cutting costs, with only two major rail carriers serving Florida in CSX and Norfolk-Southern. When something goes wrong, this trend toward consolidation and cost-cutting can lead to paralyzing bottlenecks.[42] Another problem with so much consolidation is that the railroads exercise a fair degree of market power, though in the case of Florida, this may be offset by the use of other modes such as barges. Moreover, there is really no resale market for coal, given the nature of the commodity, so electric utilities have little recourse but to deal with railroads on their terms. This situation reduces their control of transportation costs. What complicates matters further, however, is that a utility's decision to contract for coal of specified characteristics ties it closely to a unique mine-mouth and transportation combinations resulting from environmental compliance requirements or other factors.[43]

When faced with coal transportation disruptions to supply, electric utilities generally rely on their inventories or switch to alternative fuels or spot market purchases.[44] However, as noted, stockpiles have been declining for years, down 26 percent from 1989 to 2005.[45] Transportation disruptions also can drive up natural gas prices as utilities switch to natural gas for generation. According to NARUC, the country's four largest railroads have reduced coal delivery to contract customers by 10-25 percent due to both service and capacity problems.[46] In light of the uncertainties surrounding rail capacity and investment issues, the EIA projects coal transportation costs to keep rising until they peak in 2010 at 8 percent above 2004 levels, and then fall to 3.3 percent above 2004 levels in 2030 for coal originating in the East.[47] Despite these problems, long-term transportation contracts in combination with long-term coal contracts can offset much of the uncertainty in forecasting delivered coal costs.

Nuclear

The fuel for nuclear plants is a much smaller component of operating costs compared to that of coal-fired or natural gas-fired plants. Prices for milled uranium tend to have little volatility but wholesale prices of milled uranium increased by 41 percent from $10.15 per pound in 2001 to $14.36 per pound in 2005. According to EIA, the weighted average price of uranium increased by almost 14 percent from 2004 to 2005.[48] Most of the milled uranium is purchased abroad (60 percent in 2005), and purchase prices from foreign suppliers increased more than the weighted-average price from 2001-2005.[49] The costs reflected above do not capture any incremental costs for enriching the uranium and converting it into nuclear fuel.[50]

Siting and Permitting Requirements

Generation

One source of uncertainty for new coal and nuclear plants is the set of conditions that might be placed upon them in siting and permitting proceedings, especially because many of these plants will be using either updated conventional technologies or new technologies for coal-fired generation. Newer technologies for coal-fired power are often perceived by the public and decision-makers as the same old and dirty technologies used in the past. Technologies for nuclear facilities may be perceived as dangerous or unsafe. These new facilities would be in stark contrast to plants approved in Florida in recent years which have been gas-fired using more traditional technologies that have the reputation of being cleaner relative to coal and safer and less costly relative to nuclear power. In Florida, all proposals for electric power plants are subject to FPSC proceedings to establish the need for the plant and to Siting Board (Governor and Cabinet) proceedings for approval of the site and construction and operation of the plant pursuant to the state's Power Plant Siting Act. Legislation enacted in 2006 (SB 888) streamlined the process for utilities seeking siting approval of new power plants.[51] Still, even with streamlined siting processes, public resistance to such facilities may be sufficient to significantly delay or cancel projects. The conditions for the plant's operation accompany the final order approving the utility's application for the plant and additional conditions may be imposed on proposed plant operations during post certification review in response to public concerns about the project, and thereby potentially raising costs unnecessarily.[52] In addition to Florida's permitting process, the federal government has its requirements for permits that must be approved for various federal programs. The review of these permits may be combined with the certification process but in some cases may be separate.[53]

The 2006 legislation (SB 888) also included specific provisions to streamline the siting process for nuclear power plants. Electric utilities were authorized to recover the costs of siting, design, licensing, and construction of a nuclear power plant before it generates electricity. In theory, the streamlined process reduces the risk to investors who are wary about future nuclear plant construction. In addition to receiving state siting approval, nuclear power plants must be licensed by U.S. Nuclear Regulatory Commission which has responsibility for protecting public health and safety and maintaining national security. The NRC issues early site permits and standard design specifications and combined construction and operating licenses. It can also revoke licenses, close plants, and impose fines for safety violations. As of August 2006, several companies, including Progress Energy and FPL, have either applied for or are considering applying for licenses for 17 new nuclear plants.[54] According to the Nuclear Energy Institute, of the 104 existing nuclear plants in the nation, 44 reactors have applied for 20-year license extensions and an additional 36 have filed for or are expected to file for license renewals.[55] Although the siting and licensing processes have been streamlined, it still might take up to ten years or more from plant approval to completion of construction. So investors would need to be convinced that the long lead time reduces their risk.[56]

Transmission

While new plants will be needed to meet projected demand, transmission lines also will be needed for the same reason. A recent survey by Edison Electric Institute (EEI) of its members found that investor-owned utilities planned to spend $31.5 billion for transmission projects from 2006-2009, nearly a 60 percent increase over the previous four years (2002-2005).[57] Among the factors driving this greater investment is the proposed shift to more coal-fired generation units that tend to be remote from population centers. The same concerns over cost recovery for plant construction likewise apply to transmission projects. Large transmission projects also face siting uncertainties because of the "not in my backyard" syndrome, which is multiplied by the number of affected parties who will be impacted by the new transmission facility, and approval and oversight procedures to which such projects are subjected.

Relief may be in sight for siting and permitting lines. At the national level EPACT 2005 created a designation of "National Interest Transmission Corridor" in which line approvals may revert to federal jurisdiction if affected state and local governments cannot agree on, and push through, siting and permitting of new lines. In Florida, the same legislation (2006 SB 888) enacted to streamline the siting process for Florida's generating plants also streamlined the siting process for Florida's high-voltage transmission lines.

Capital Costs and Technology

As prices for natural gas and oil continue to increase, electric utilities have been giving more serious consideration to both clean coal and advanced nuclear generation technologies. For electric utilities, among the greatest uncertainties is their ability to recover the capital costs for such plants and the reliability of these technologies.

Clean Coal

Integrated Gasification Combined Cycle (IGCC) technology, in particular, has received considerable press because it can be designed to more easily capture and sequester carbon dioxide, and inject it underground, than other coal-fired technologies. IGCC also has the advantage that sulfur and mercury are removed pre-combustion in the gasification process and nitrogen oxide control technologies are the same as those used for natural gas and are less expensive than traditional coal-fired power plants. Estimates vary but IGCC's probable cost is 10 percent to 20 percent higher than conventional pulverized coal plants.[58] There are always uncertainties with projecting capital and operating costs for the commercial operation of plants that use fairly new technologies like IGCC because new technologies in the past had a reputation of being unreliable during their early years of commercial operation. Compounding these uncertainties has been the unpredictability of state regulators. For example, the Wisconsin Public Service Commission rejected a proposal by WE Energies of Milwaukee in 2003 to build a coal plant using a new technology, on the grounds that it was too expensive and would raise electricity prices. On the other hand, the Public Utilities Commission in Ohio allowed

American Energy Power to pass on a portion of the pre-construction costs of a clean technology coal plant.[59]

Mitigating some of the risks surrounding cost recovery and high investment costs, at least to some extent, are various tax incentives authorized in the Energy Policy Act of 2005 (EPACT 2005). There is a 20-percent investment tax credit for IGCC projects and a 15 percent investment tax credit for other advanced coal-based projects. Up to $800 million has been allocated for IGCC projects, up to $500 million for other advanced coal-based projects, and up to $350 million for industrial gasification projects. But these incentives are limited in nature to first movers whose project experience may not be available for several years.

Nuclear Power

Estimating the capital costs of a new nuclear plant can be tricky because no new nuclear plants have been constructed and become commercially operational in the U.S. in the past ten years, and no new plants have been ordered since 1979. The last plant to become commercially operational was TVA's Watts Bar reactor in June 1996. Few new nuclear plants are under construction outside the United States. This means that there is a lack of reliable recent information about actual construction costs for nuclear plant construction in the United States. The nuclear industry also has a history of greatly underestimating construction costs. However, according to Paul Joskow, publicly available data on recent nuclear plants suggests that construction cost estimates of $2,000 per kilowatt is a good base case cost estimate.[60] This estimate includes all of the owner's costs, with a five-year construction period. Joskow notes that at that price nuclear power would not be competitive with either clean coal plants or natural gas-fired plants unless construction costs, including financing, for nuclear plants are reduced by about 25-30 percent or coal or natural gas plants are taxed on carbon emissions.[61] In addition to the existing, known technologies used in the US, there are other potential processes and technologies that may be part of a nuclear expansion plan, but the lack of experience implies uncertain costs going forward. [62]

In an effort to mitigate some of the cost risk of these new plants,[63] EPACT 2005 authorizes $1.25 billion to build a prototype of a reactor that could be used to produce electricity and hydrogen. EPACT 2005 also provides a production tax credit of 1.8 cents per kilowatt-hour for the first eight years of the plant's operation, but is limited to $125 million per gigawatt of capacity per year, and not to exceed an aggregate of 6 gigawatts of new capacity over the eight-year period. Moreover, EPACT 2005: updated the Price-Anderson Act Amendment of 1954 to limit operator liability for nuclear accidents for all nuclear units brought on line through 2025; provides loan guarantees of up to 80 percent of project cost, which applies to all technologies, including nuclear plants, that do not emit greenhouse gases; and provides insurance against regulatory delays. Finally, EPACT 2005 modifies the tax treatment of funds used to decommission nuclear plants that are not rate-based. Whether these provisions are adequate incentives for investments in nuclear power plants remains to be seen. However, we can certainly expect more serious consideration of nuclear power plant construction in the U.S. given these incentives, coupled with streamlined licensing processes at the state and federal levels. Other factors that make nuclear power plant construction a more viable prospect are the

significant operational improvements of these plants in the past 15 years (average capacity factors of about 90 percent in 2005 compared to 66 percent in 1990) and their emissions profile.

Perhaps the biggest uncertainty, after capital costs, connected with future nuclear facility projects relates to storage facilities for spent nuclear fuel. Because the federal government has not begun to collect spent nuclear fuel, Florida's five nuclear power generators have been storing the spent fuel at their sites in spent fuel pools. However, spent fuel pools are expected to reach storage capacity within the next six years. Florida ratepayers have already paid into the federal Nuclear Waste Fund over $690 million (over $1 billion with interest) to remove the spent fuel.[64] But the uncertainty concerning long-term disposition of the fuel is sure to enter into deliberations about new or expanded nuclear power plant construction in the foreseeable future.

Environmental Compliance Costs

Environmental compliance costs must also be factored into cost estimates for new generating capacity regardless of the type. With respect to sulfur dioxide, nitrogen oxides, mercury, and particulates, there is a great deal of certainty about the compliance technologies that must be installed to satisfy the best available control technology (BACT) standard. Power companies in Florida will also have to comply with the newly promulgated Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). According to EPA, CAIR is projected to help Florida sources by 2015 reduce emissions from 2003 levels by 308,000 tons for sulfur dioxide and by 192,000 tons for nitrogen oxide emissions.[65] The only uncertainties are the ultimate allowance price for utilities that buy or sell in the market. However, the costs for allowance transactions are generally not large relative to other costs for installing and operating new facilities. The biggest risk associated with these programs for Florida consumers arises because incremental environmental costs may be recovered through the statutorily-authorized Environmental Cost Recovery Clause. If compliance cost assumptions used for cost recovery determinations are flawed, customers of Florida's investor-owned utilities might bear some of the burden. Finally, existing coal-fired plants are affected by the federal New Source Review (NSR) program – a source of uncertainty because of ongoing litigation. There may be some resolution, however, once the U.S. Supreme Court takes up a case on appeal concerning alleged violations of the Clean Air Act by eight of Duke Energy's coal-fired power plants. The final disposition on NSR directly affects only existing units, but indirectly affects decisions on the number and type of new units if old units are retired rather than retrofitted to meet NSR requirements.

The largest uncertainty for capacity planning in Florida is the disposition of federal policy concerning carbon dioxide emissions – a significant contributor to global warming.[66] The amount of carbon dioxide emitted is highest for coal. Gas-fired combined cycles produce half or less of the carbon dioxide emissions per MWh of energy produced compared to coal-fired plants for two reasons: the higher efficiency of combined cycle units and the lower carbon content of natural gas. To reduce greenhouse gas emissions, electric utilities considering clean coal technologies are faced with several clean coal options involving the sequestration of carbon dioxide. Sequestration involves a series of processes including the capture, compression, transport, and storage of carbon

dioxide. The cost of sequestration will depend on several factors: the type of power plant, the distance via pipeline to the storage site, the properties of the storage reservoir, and the opportunities (such as enhanced oil recovery) for selling the captured carbon dioxide. Some of that uncertainty might be reduced in the future as more initiatives are undertaken, like the FutureGen Initiative, to test various options for carbon capture and storage. There is also still much uncertainty about the costs of carbon capture and disposal technologies.[67]

In the meantime, all eyes are currently on the efforts of the Regional Greenhouse Gas Initiative – a consortium of seven Northeastern and Mid-Atlantic states that will implement a regional, mandatory, market-based cap and trade program for carbon dioxide. On August 15, 2006, this consortium issued a model set of regulations for the cap and trade program. The program calls for carbon dioxide emissions to be capped beginning in 2009 at current levels – about 121 million ton annually – until 2015. From 2015 until 2019, the participating states would be required to reduce their emissions incrementally to achieve a reduction of 10 percent in carbon dioxide emissions by 2019. States may issue one allowance or permit for each ton of carbon dioxide emissions allowed by the cap. The total amount of allowances will be equal to the cap in the region. The program applies to all coal-fired, oil-fired, and gas-fired electric generating units in the participating states with a capacity of 25 megawatts or more. At least 25 percent of a state's allowances are to be used for purposes that support strategic energy or consumer benefit purposes.[68] On August 30, California's officials announced the passage of legislation to reduce carbon dioxide emissions by 25 percent by 2020, with the intent of reducing the aggregate down to 1990 levels. The first major controls will begin in 2012. This initiative will use a state-wide market cap and trade system.[69] Whether the RGGI model, California model, or some version of either one will be mandated for other states in the future has yet to be determined.

Renewable Energy

Renewable energy represents a very small segment of Florida's energy portfolio for electricity generation. However, there is growing interest in renewables in Florida and the nation because of concerns with pollution and climate change and the supply constraints on fossil fuels. Moreover, the FPSC requires electric utilities to "aggressively integrate nontraditional sources of power generation including co-generators with high thermal efficiency and small power producers using renewable fuels into the various utility service areas near utility load centers to the extent *cost effective and reliable*." (italics added) [70]

Much of Florida's energy from renewable energy comes from hydropower and biomass. According to an assessment of hydropower conducted in 1998, undeveloped hydropower capacity in Florida accounts for a very small portion of the future resource mix –61 megawatts of nonmodeled potential.[71] However, biomass appears to have some potential in the state and is considered "carbon neutral" for the purposes of climate change policy. Florida's utilities purchase 506 megawatts of biomass energy from non-utility generators. In August 2006, the FPSC approved a petition by Progress Energy to purchase energy from a 116 megawatt facility near Lake Okeechobee that will use a

bamboo-like grass called Arundo "e-grass." This grass will be harvested on 15,000 acres and will be processed into a liquid fuel using a pyrolysis process. The biomass plant is scheduled to come on line by December 2009.[72]

Wind and solar photovoltaics are not feasible or cost-effective for Florida at this time.[73] However, Florida's potential for solar technology, especially solar thermal, to offset electricity generation is high based on ratings from the National Renewable Energy Laboratory. In addition, federal, state, and, in some instances, utility rebates, might make the solar thermal technology for residential use – hot water heater or pool heater -- fairly competitive given increasing prices for electricity supplied by primary fuels.[74]

To a certain extent, utility costs for electricity generation using renewable sources might be offset by the federal Renewable Energy Production Incentive program. This program provides financial incentive payments for electricity sold and produced at an amount equivalent to 1.5 cents per kilowatt-hour for the first ten years of operation, subject to annual appropriations. This tax credit is scheduled to expire at the end of 2007, a deadline some advocates claim is not sufficient for planning and permitting of some renewable generating facilities.[75] In addition, a state production tax credit equal to 1.0 cent per kilowatt hour may be claimed for energy produced or sold on or after January 1, 2007 through June 30, 2010. The combined total amount of credits granted to all taxpayers in any given year is $5 million.[76]

Demand Side Management and Energy Efficiency

Florida's five investor-owned electric utilities and two municipal utilities, Orlando Utilities Commission and JEA, are subject to the Florida Energy Efficiency and Conservation Act (FEECA) with the objectives of reducing the growth rates of utility peak-demand, reducing and controlling the growth rates of electricity consumption, and reducing the consumption of fossil fuels. FEECA effectively puts DSM and conservation on the same footing with generation options for meeting future demand.

In order for DSM programs to be implemented, all customers must benefit through reduced, or at least not increasing, electric bills due to the deferral of new power plant construction, reduced production costs, and improved reliability. The FPSC allows the utilities to recover from their ratepayers the costs associated with approved DSM programs. Since 1980, approved DSM programs offered by Florida's utilities have resulted in a cumulative postponement of an estimated 4,951 megawatts of additional capacity to meet summer peak demand and 5,563 megawatts of additional capacity to meet winter peak demand.[77] The cost-effectiveness of individual electric utility plans really depends on the extent to which they are being used to defer construction of a plant that is more expensive to build relative to costs of providing the utility's existing capacity. Obviously, rising fuel prices for electricity generation make utility-sponsored DSM and EE programs increasingly more attractive -- a trend that has been discernible in other states.[78] Because the cost-effectiveness of those programs will vary over time, the FPSC requires the participating utilities to re-evaluate them regularly.

While DSM programs, such as direct load control of water heaters, pool pumps, and air conditioners, are designed to reduce peak load (and the corresponding capacity to generate power at peak, that load is generally shifted to other hours of the day. Energy efficiency (EE) programs, such as incentives to install high efficiency air conditioning

units, do not shift load but reduce it over all hours of the day. In fact, greater energy efficiency reduces the cost-effectiveness of DSM programs by limiting the incremental savings from such programs. On the other hand, rising fuel prices for electricity generation make EE programs increasingly more attractive -- a trend that has been discernible in other states.[79]

Electric utilities cannot control consumer response to incentives provided in approved DSM and EE plans. Therefore, they will always experience uncertainty as to whether their goals for deferred capacity from such plans actually materialize.[80] Periodic utility evaluations of and adjustments to DSM plans, as required by the Commission, can reduce but never eliminate that uncertainty since implementation of projects approved in the plans relies on consumer behavior.

Public Support

Public support for new generating plants is also an uncertainty for electric utilities, particularly if the utility contemplating the additional generation is municipal. Although public support for nuclear power is growing, opinion is still pretty divided with respect to expanded use of that energy source. According to a survey of the Pew Research Center, 44 percent of those surveyed favored promoting an increased use of nuclear power and 49 percent were opposed. The same survey found that slightly over half (52 percent) supported as an important priority for U.S. energy policy more energy conservation and regulation on energy use and prices. A smaller percentage, but still a substantial 41 percent, supported a national emphasis on exploration, mining and drilling, and construction of new power plants. Although an overwhelming majority of 82 percent wanted to see increased federal funding for wind, solar, and hydrogen technology, it is not clear that they would be willing to pay a premium for electricity generated from those sources.[81] There is a substantial literature on consumers' willingness to pay more for "green power." As one study noted, "In general, this literature finds that many households state a willingness to pay a premium for green electricity, yet actual participation in a green-electricity program depends on program structure, household characteristics, attitudes related to the environment, and the existence of "warm-glow" motives for participation."[82]

Conclusion

As they look toward the future, Florida's electric utilities will be faced with many difficult decisions in securing adequate energy supply to meet growing demand. Energy expenditures per person and energy consumption per person have increased steadily in the past 25 years.[83] A switch from natural gas combined-cycle power plants – the preferred option for new generating units in recent years – to other types of fuel sources and technologies poses a whole new array of promising outcomes but also many challenges, as explained above.

- More efficient IGCC coal plants show promise in demonstration projects but are expensive and largely untested at the commercial level. The issue of transportation also poses problems as long-term contracts begin to expire. The

capture and sequestration technologies are likewise promising but still largely untested on a commercial basis. It is also not clear whether clean coal generation technologies will be cost-effective in the competitive market if a national carbon emissions policy is mandated.

- Nuclear power is looking more attractive in terms of growing concerns about carbon dioxide emissions. However, the newest technologies have not been used commercially in this country and there still remain many unresolved problems related to storage, long-term disposition of hazardous wastes, and security.
- It is not clear whether nuclear or coal power plants using advanced technologies will be cost-effective without significant federal and state government subsidies. Site approval and licensure processes have become streamlined and there is growing government support for nuclear power and coal-fired generation using cleaner technologies. Yet, electric utilities continue to be concerned about uncertain regulatory treatment of, particularly cost recovery for, plants using new technologies.
- Renewables are not considered particularly economic at this point for most base load generation in Florida because of their high capital costs although they may become increasingly attractive as supplementary sources under certain circumstances.
- DSM is not controllable by the utilities and only affects a relatively small amount of load. Moreover, utilities must periodically reassess the cost-effectiveness of their DSM plans and make necessary adjustments to those plans as fuel prices and conditions affecting energy efficiency change.

What is clear is that the conflicts identified by Dr. Holden, cited at the beginning of this essay, will continue to underpin planning efforts in the midst of ongoing uncertainties about: future fuel, procurement, and transportation costs; regulatory treatment; and clean air and climate change policies. However, there is no going back to the days of secure and plentiful fossil fuel supplies. Therefore, we need to have ongoing dialogues about the implications of leaving those uncertainties unresolved and the steps that must be taken to manage them and thereby reduce risk to investors and consumers, alike.

Endnotes

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[66] John Holdren (p. 10) notes that about 27 billion metric tons of carbon dioxide were emitted from fossil fuel burning worldwide in 2004.

[67] The Intergovernmental Panel on Climate Change (September 2005), *Special Report on Carbon Dioxide Capture and Storage*, Summary for Policymakers, at p. 10; available at: http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_SummaryforPolicymakers.pdf. The report noted: "Since neither Natural Gas Combined Cycle, Pulverized Coal nor Integrated Gasification Combined Cycle systems have yet been built at a full scale with CCS, the costs of these systems cannot be stated with a high degree of confidence at this time. In the future, the costs of CCS could be reduced by research and technological development and economies of scale."

[68] Regional Greenhouse Gas Initiative (August 15, 2006), "States Reach Agreement on Proposed Rules for the Nation's First Cap-and-Trade Program to Address Climate Change;" available at: http://www.rggi.org/docs/model_rule_release_8_15_06.pdf.

[69] Juliet Eilperin (September 1, 2006), "California Tightens Rules on Emissions," *The Washington Post*; available at: http://www.washingtonpost.com/wp-dyn/content/article/2006/08/31/AR2006083100146_pf.html.

[70] Rule 25-17.001 (5) (d) of FPSC.

[71] Alison M. Conner and James E. Francfort, "U.S. Hydropower Resource Assessment for Florida," Prepared for the U.S. Department of Energy; available at: http://hydropower.id.doe.gov/resourceassessment/pdfs/states/fl.pdf.

[72]LCG Consulting, (August 17, 2006), "Florida PSC Approves Agreement for New Biomass Plant in Florida," Energyonline; available at: http://www.energyonline.com/Industry/News.aspx?NewsID=7070&Florida_PSC_Approves_Agreement_for_New_Biomass_Plant_in_Florida.

[73] See *An Assessment of Renewable Electric Generating Technologies for Florida*, prepared by the Florida Public Service Commission and Department of Environmental Protection, January 2003 and Wind Energy Resource Atlas of the United States; available at: http://rredc.nrel.gov/wind/pubs/atlas/chp3.html#southeast.

[74] Nathan Crabbe (September 13, 2006), "Subsidizing Solar Energy," The Gainesville Sun, at 1B; available at: http://www.gainesville.com/apps/pbcs.dll/article?AID=2006209130308.

[75] Union of Concerned Scientists (April 13, 2006), "Renewable Energy Tax Credit Saved Once Again, but Boom-Bust Cycle in Wind Energy Continues;" available at: http://www.ucsusa.org/clean_energy/clean_energy_policies/production-tax-credit-for-renewable-energy.html.

[76] The Florida Energy Production Tax Credit is authorized under 2006 SB 888.

[77] FPSC (February 2006), *Annual Report on Activities to the Florida Energy Efficiency and Conservation Act*, at p. 10

[78] The Brattle Group, "Why are Electricity Prices Increasing? An Industry-Wide Perspective." Prepared for the Edison Foundation, June 2006, at 33. Examples include California's approval of $2 billion for an energy efficiency program from 2006 through 2008 and $48 million in new efficiency programs mandated in Arizona in 2005.

[79] The Brattle Group, *supra* note 6, at 33. Examples include California's approval of $2 billion for an energy efficiency program from 2006 through 2008 and $48 million in new efficiency programs mandated in Arizona in 2005.

[80] See for example "Analysis of United States Utility Conservation Programs" by Franz Wirl and Wolfgang Orasch in *Review of Industrial Organization*,13: 467-486, 1998. and "Demand-Side management and Energy Efficiency in the United States" by David S. Loughran and Jonathan Kulick, *Energy Journal*, Vol. 25, No. 1, pp. 19-43, 2004.

[81]The Pew Research Center (February 7, 2006), "Iran a Growing Danger, Bush Gaining on Spy Issue;" available at: http://people-press.org/reports/display.php3?ReportID=269.

[82] Matthew J Kotchen and Michael R. Moore (October 19, 2004), "Conservation Behavior: From Voluntary Restraint to a Voluntary Price Premium," Williamstown, MA: Williams College, at p. 3; available at: http://www.eere.energy.gov/greenpower/resources/pdfs/04_10_consrvbehav.pdf.

[83] EIA, AEO 2006, Figure 31; available at: http://www.eia.doe.gov/oiaf/aeo/pdf/trend_2.pdf.