(WHEN) TO BUILD OR NOT TO BUILD?: THE ROLE OF UNCERTAINTY IN NUCLEAR POWER EXPANSION

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ABSTRACT

With concerns over global climate change, U.S. policymakers are exploring ways to reduce domestic dependence on coal and natural gas. No new nuclear plants have been ordered since 1978. However, federal and state policies and legislation have attempted to reduce risks to nuclear plant developers or re-allocate them to customers and to improve expected returns from investments in nuclear energy capacity. Past regulatory decisions and court decisions also have implications for cost recovery. Investments in nuclear power plants are irreversible and involve uncertainties during both construction and commercial operation. Uncertainties confronted by developers of merchant plants and price-regulated plants differ due to the regulatory and market paradigm in which these plants operate.[2] Texas and Florida provide useful case studies in their respective policies toward new generation, including nuclear generation. Texas has a largely restructured electricity market, and Florida's power generation is subject to traditional rate-of-return regulation. In particular, the regulatory/market framework affects both the expected returns on investment and the likelihood and timing of the recovery of investments made in nuclear plants. The effectiveness of current federal and state policies will depend on the developers' perceptions of how risks associated with uncertainties during construction (including those

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2. In the context of this article, the term "developers" refers to both developers of merchant plants and price-regulated utilities unless expressly stated.

uncertainties surrounding changing governmental regulations) affect construction costs, how risks linked to revenue and operating uncertainties during a plant's commercial operation affect the timing and potential for cost recovery, and ultimately how these risks affect the decision to build nuclear plants. These risks undoubtedly matter to developers whose reputations may be affected by the long-term financial viability of such projects. We use an option value model developed by Robert Pindyck (1993) and extend that model to explain the uncertainties facing prospective developers of nuclear plants. We conclude with several observations about strategies states may consider undertaking to mitigate investment risk.

Based on recent policy initiatives, nuclear power generation in the United States is being revived as an option for electricity capacity investment. As of April 23, 2008, the Nuclear Regulatory Commission (NRC), the nation's regulator of the construction and operation of commercial nuclear power units, listed twenty-three expected applications for new plants: thirty-four units in fifteen states, mostly in the South and Northeast.[3] The plans call for many of these units to be constructed next to existing ones.[4] Currently, one hundred and four commercially operational nuclear generating units are licensed in the United States. Through 1998, all nuclear generation in the United States was produced by regulated utilities. However, the percentage has been declining and was sixty percent by 2003 due to the sale of regulated nuclear plants in restructuring states to unregulated entities, thus converting these plants from traditionally regulated plants into merchant plants.[5]

A confluence of factors makes the construction of these plants more attractive now than in the past: uranium is located in regions of the world that are more politically friendly to the United States; the current fleet of plants has fewer unscheduled shut-downs than in the past, resulting in on line operations of ninety percent of the time or greater;[6] prices of natural gas have soared, making nuclear power-generated energy prices more cost-competitive;[7] and concerns with fossil fuel emissions linked to climate change have increased public support for nuclear power.[8] Coal-fired plants, large emitters of greenhouse gases,[9] and combined cycle natural gas plants, with much higher fuel costs than coal but lower

3. *See* UNITED STATES NUCLEAR REGULATORY COMMISSION (NRC), EXPECTED NEW NUCLEAR POWER PLANT APPLICATIONS UPDATED APRIL 23, 2008 (2008), http://www.nrc.gov/reactors/new-licensing/new-licensing-files/expected-new-rx-applications.pdf.

4. *Id.*; *see also Atomic Renaissance*, THE ECONOMIST, Sept. 8, 2007, at 73.

5. For the percentage change, see IbisWorld, *Nuclear Power Generation in the US*: *22111b*, Apr. 10, 2008, at 15, *available at* http://www.ibisworld.com. In this article, we refer to a "merchant plant" as any plant that generates electricity expressly for sale in wholesale markets through bilateral contracts or in day-ahead transactions. In contrast to utilities, merchant plants are not entitled to any cost recovery because they have no captive customer base and are not subject to traditional rate regulation. At the same time, their returns are not subject to price caps because investors are bearing greater risks.

6. Energy Information Administration (EIA), Nuclear Power: 12 Percent of America's Generating Capacity, 20 Percent of the Electricity, http://www.eia.doe.gov/cneaf/nuclear/page/analysis/nuclearpower.html (last visited May 5, 2008).

7. Natural gas is the dominant generating fuel in some markets and often is the fuel associated with the marginal generating unit setting the price in electricity markets, especially at peak. As the price of natural gas increases, the relatively low fuel price for nuclear power generation becomes increasingly attractive. The cost (per million BTU) of natural gas for electricity generation increased from $2.64 in 1996 to $6.94 in 2006 (nominal prices). *See* ENERGY INFO. ADMIN., U.S. DEP'T OF ENERGY, SUMMARY STATISTICS FOR THE UNITED STATES, 1995 THROUGH 2006 tbl.ES 1 (2007), http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfilees1.pdf (discussing cost of fuel at electricity generators as cents per million BTU).

8. *Nuclear Power's New Age*, THE ECONOMIST, Sept. 8, 2007, at 13.

9. Greenhouse gases include carbon dioxide (CO_2), methane, and nitrogen oxides (NO_X).

emissions, are the main competitors of nuclear power plants for base load generating capacity. Nuclear plants have extremely low fuel costs[10] and do not emit the products of fossil fuel combustion into the air.[11] Recently, plans for new coal-fired plants have been rejected on the basis of carbon emissions concerns. For example, on October 18, 2007, the Kansas Department of Health and Environment became the first government agency to turn down an air quality permit for two proposed 700-megawatt coal-fired plants in the western part of the state on the grounds that the proposed plants would emit pollutants that contribute to climate change.[12] Utilities are also vulnerable to citizen concerns: for example, in 2007 the municipal utilities of Gainesville, Florida and Orlando, Florida dropped their respective plans for coal plants.[13] Both coal and nuclear plants are designed to operate continuously, generating base load power, so considerations affecting the type of additional base load capacity have been shifting increasingly toward nuclear power.

Despite these overall encouraging developments for nuclear power advocates, memories of soaring interest rates, construction cost-overruns, poor operating performance, and accidents at Three-Mile Island (1979) and Chernobyl (1986) have lingered on and have been difficult to extinguish in the minds of regulators, developers, and the public. Indeed, safety concerns stemming from those accidents and the financial woes

10. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2007 88 fig.65 (2006) http://tonto.eia.doe.gov/ftproot/forecasting/0383(2007).pdf. Fuel prices for nuclear energy historically have been lower than coal, natural gas, and liquid fuels (1995-2005) and are projected to remain lower through 2030. *Id.*

11 According to the EIA, "…waste from a nuclear plant is primarily a solid waste, spent fuel, and some process chemicals, steam, and heated cooling water. Such waste differs from a fossil fuel plant's waste in that its volume and mass are small relative to the electricity produced … nuclear waste also differs from fossil fuels in that spent fuel is radioactive while only a minute share of the waste from a fossil plant is radioactive. Solid waste from a nuclear plant or from a fossil fuel plant can be toxic or damaging to the environment, often in ways unique to the particular category of plant and fuel. Waste from the nuclear power plant is managed to the point of disposal, while a substantial part of the fossil fuel waste, especially stack gases and particulates are unmanaged after release from the plant." EIA, Nuclear Issues Paper, *Nuclear Power and the Environment,* http://www.eia.doe.gov/cneaf/nuclear/page/nuclearenvissues.html (last visited May 5, 2008).

12. Kansas Department of Health and Environment, *KDHE Denies Sunflower Electric Air Quality Permit*, Oct. 18, 2007, http://www.kdheks.gov/news/web_archives/2007/10182007a.htm. At the time of writing, Kansas Governor Sebelius vetoed two bills—2008 House Sub. for S.B. 327 and 2008 House Sub. for S.B. 148—that would have authorized approval of the plants. Another bill—2008 Senate Sub. for H.B. 2412—was subsequently enacted and was submitted to the Governor.

13. Orlando Utilities Commission, a subsidiary of Southern Company, planned to operate an advanced coal-fired plant with a capacity of over 4,400 MW. Southern Company announced the cancellation of the unit on November 14, 2007. *See* LCG Consulting, *Southern Cancels IGCC Coal Plant in Florida,* ENERGYONLINE, Nov. 15. 2007, http://www.energyonline.com/Industry/News.aspx?NewsID=7206&Southern_Cancels_IGCC_Coal_Plant_in_Florida. The Gainesville City Commission decided to exclude coal from its considerations for additional electric capacity. *See* Nathan Crabbe, *Gainesville Goes Green*, THE GAINESVILLE SUN, Dec. 31, 2007, http://www.gainesville.com/article/20071231/NEWS/712310310.

resulting from increased costs to address these concerns contributed to increased investment risk and, therefore, the cancellation of ninety-six nuclear projects in the United States from 1974 to 1994.[14] As recently as July 2007, an earthquake in Japan revealed that Tokyo Electric Power's nuclear power plant in Kashiwazaki was not designed to withstand powerful tremors; the plant was shut down due to safety concerns.[15] As one consultant observed, "[t]here is a very powerful feedback loop from real and perceived nuclear performance into public opinion and public policy. The favorable feedback is very gradual; the negative feedback can be devastatingly quick."[16]

So the ghosts of the past must be reckoned with, suggesting that prospective developers[17] of new nuclear plants continue to face formidable challenges and looming uncertainty that they will recover the costs of their investments in nuclear plant construction. In this article, we analyze how federal and state policies pertain to or affect two types of cost uncertainty during the construction phase—technical and input cost uncertainty, as well as uncertainty associated with commercial operation—and revenue and operating uncertainty. In addressing state policies and to make our discussion more concrete we focus on two states, Texas and Florida, to analyze the implications of their policies for construction and commercial operation uncertainty. Texas is a largely restructured state.[18] This means that the price of electricity is determined through organized wholesale markets rather than through the

14. Rebecca Smith, *Power Producers Rush to Secure Nuclear Sites; First to Develop Plans Could Tap $8 Billion in Federal Subsidies*, WALL ST. J., Jan. 29, 2007, at A-1.

15. Gabriella Coppola, *Fault Lines Increase Japanese Worries*, WALL ST. J. ONLINE, July 18, 2007, http://blogs.wsj.com/energy/2007/07/18/fault-lines-increase-japanese-worries.

16. Bruce Lacy, President, Lacy Consulting L.L.C., U.S.A., *Nuclear Investment: Performance and Opportunity*, World Nuclear Association Annual Meeting, http://www.world-nuclear.org/sym/2006/pdf/lacy.pdf. The fragility of public opinion is also evident in findings from a Gallup poll in March 2006 and March 2007. The March 2007 Gallup poll found that 50% of Americans support the expanded use of nuclear energy, down from March 2006 (55% of the public), but up from 2003, when only 43% supported such an expansion. The higher level of public support in 2006 compared to 2007 might have been due to rising gas prices in 2006. Lydia Saad, *Most Americans Back Curbs on Auto Emissions, Other Environmental Proposals*, THE GALLUP POLL, http://www.gallup.com/poll/27100/Most-Americans-Back-Curbs-Auto-Emissions-Other-Environmental-Proposals.aspx.

17. The term "developers" or "nuclear plant developers" in the context of this article refers to both merchant developers and utility companies.

18. We take restructuring as the paradigm of allowing generation to compete in organized wholesale markets and allowing end-use customers to choose their supplier of electricity where prices are determined by market conditions rather than through a regulatory process. By this definition according to the EIA, 14 states currently implement restructuring: Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Ohio, Michigan, Illinois, and Texas. Eight states have suspended all or parts of their restructuring programs: California, Oregon, Nevada, Montana, Arizona, New Mexico, Arkansas, and Virginia. The remaining 26 states in the continental United States have not restructured. *See* EIA, *Energy Restructuring by State*, Apr. 2007, http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

administrative regulatory process.[19] Texas has a competitive wholesale electricity market and retail market where power is supplied by merchant plants at market-determined prices that are not subject to traditional rate regulation. By contrast, in Florida power is supplied and delivered by vertically integrated electric utilities, and Florida's electricity market is subject to traditional rate regulation, except for municipal utilities and rural electric cooperatives.

Part I of this article explains the nature of the uncertainty facing prospective nuclear plant developers. Central to our discussion is a model developed by Robert Pindyck which explicitly applies to construction cost uncertainties facing prospective developers contemplating investments in and construction of rate-regulated nuclear power plants.[20] We expand the application of the model to another set of uncertainties—that of revenue and operating uncertainty during commercial operation. We also identify sources of uncertainty that are beyond the control of the nuclear plant developer and discuss how these uncertainties might be mitigated, if at all.

Part II discusses how the regulatory and market environments affect the ability of nuclear plant developers to mitigate risks associated with technical and input cost uncertainty that affect construction costs and how to mitigate the risks associated with revenue and operating uncertainty that affect cost recovery. Developers of merchant plants in a restructured state like Texas face different options for mitigating technical and input cost uncertainties during construction and confront different cost recovery concerns than their counterparts considering new plant construction in a rate-regulated environment like Florida. In a rate-regulated environment, nuclear plant developers must contend with the implications of case law and a statutory framework that signals the available options for mitigating uncertainties during construction and the type of cost recovery treatment that could be expected. We also briefly

19. In Texas, all regions in the state that fall within the jurisdiction of the Electric Reliability Council of Texas (ERCOT) are restructured. Certain regions in Texas have not been restructured yet, including the Texas Panhandle and northeast and southeast parts of the state. ERCOT serves 85% of the state's electric load and 75% of Texas' land area. *See* ERCOT, Company Profile, http://www.ercot.com/about/profile/index.html (last visited May 5, 2008); *see also* PUB. UTIL. COMM'N OF TEX. (PUCT), REPORT TO THE 80TH TEXAS LEGISLATURE, SCOPE OF COMPETITION IN ELECTRIC MARKETS IN TEXAS 12 (2007), http://www.puc.state.tx.us/electric/reports/scope/2007/2007scope_elec.pdf ("In areas outside of ERCOT, where retail supply of electricity currently remains regulated…"). Restructuring is left to state decision-making, so each state that has implemented restructuring to date is governed by its own set of statutory or regulatory processes.

20. Robert S. Pindyck, *Investments of Uncertain Cost*, 34 J. FIN. ECON. 53, 53-76 (1993). Pindyck analyzes an investment decision to delay, start, or continue to build a nuclear power plant during the 1980s by deriving decision rules that take into account two types of uncertainties explained in our article–technical and input cost. As this article was written about nuclear plant construction decisions in the 1980s, the only type of plants built at the time were subject to traditional rate regulation.

touch on assumptions underlying cost projections for nuclear power as well as cost projections for competing technologies as these influence the decisions made by developers, merchant or regulated, to proceed with a nuclear power project or not. To the extent that cost projections for nuclear power fail to fully incorporate relevant risks associated with construction and operating costs relative to those of competing technologies and deviate significantly from actual cost, developers and policymakers in future years will be less likely to support the already risky proposition of nuclear power as a viable resource option.

Part III sets the context by comparing the energy markets of Texas and Florida. In doing so, we acknowledge that every state has its own set of unique energy supply and demand challenges, and Texas and Florida are not exceptions to that observation. We highlight the common and different characteristics of construction cost and revenue uncertainties between the market-oriented environment in states like Texas and the traditional regulatory environment in states like Florida.

Part IV briefly outlines federal policies and state policies (using Texas and Florida as examples) that attempt to mitigate technical and input cost uncertainty during construction, and revenue and operating uncertainty during commercial operation. These policies range from generation and transmission siting, to cost recovery rules, to production tax credits, to loan guarantees.

I. THE NATURE OF UNCERTAINTY AND THE METHODS FOR MITIGATING UNCERTAINTY

Nuclear power projects face uncertainties and associated financial risks in the overall business climate during both construction and commercial operation. These uncertainties are magnified by the fact that nuclear power investments require large capital outlays and have a long time horizon from construction to commercial operation, and nuclear plants may be in operation for up to six decades if license renewals are authorized.

During the construction phase, uncertainties include changes in the price of materials and labor to build new facilities; the time it will take to complete construction of new plants; fragile public support for new projects during the permitting process; and state and federal regulatory changes related to construction costs and duration. Because of the capital-intensive nature of nuclear power plants and their associated cost uncertainties, a theoretical framework for making investments in plant construction and for making decisions on whether or not to start construction may prove useful. Pindyck provides such a framework for decision-making.[21] He categorizes uncertainty during the construction phase of the project into two categories: (1) technical uncertainty which relates to the amount of time, effort, and materials required to complete the project, given the prices of inputs are known,; and, (2) input cost uncertainty which relates to the cost of land, labor, and materials necessary to complete the project, whether those costs are driven by input market dynamics or regulatory dynamics affecting the actual construction, given the time, materials, and effort are known.[22]

For developers choosing to build plants with advanced designs—in spite of engineering studies and advanced scheduling—the actual amount of time and effort needed to bring the project to commercial operation is not known with certainty. This is the prime example of technical uncertainty facing nuclear plant developers. Additionally, nuclear plant developers will attempt to arrange for skilled labor and materials ranging from basic concrete and steel to steam generators and pressure vessels. As the demand for each of the components changes or the physical availability of resources becomes scarcer, the resulting changes in the price of materials lead to modifications in the overall construction cost of the project.[23] This is an example of input cost uncertainty that developers may face.

Technical uncertainty can be largely controlled or mitigated by the nuclear plant developer, according to Pindyck.[24] A developer can start a project and have information revealed to it regarding the actual amount of time, effort, and material needed to complete the new plant before completing construction. If the information reveals that the actual time, effort, and cost of materials necessary to complete the project would make it economical for the developer to proceed, the developer can continue with the project until it is completed and placed in commercial operation. However, if the information reveals the actual construction time, effort, and cost of materials necessary to bring the project to commercial operation would make it uneconomical for the developer to proceed, the developer may opt to abandon the project, and thereby avoid incurring the higher costs associated with continued work on the project.[25]

Moreover, having the option to either abandon or continue a project

21. *Id.*
22. *Id.* at 54.
23. The Keystone Center, *Nuclear Power Joint Fact-Finding*, June 2007, at 35 (discussing factors affecting costs).
24. Pindyck, *supra* note 20, at 54. Jonathan Falk applied this observation on abandoning a nuclear construction program using a model involving five potential outcomes. JONATHAN FALK, *Why Planning a Nuclear Plant Is a Good Idea Even If Building One Turns Out to Be a Bad Idea*, in THE LINE IN THE SAND: THE SHIFTING BOUNDARY BETWEEN MARKETS AND REGULATION IN NETWORK INDUSTRIES 51-58 (Sarah Potts Voll & Michael J. King, eds., 2007).
25. Pindyck, *supra* note 20, at 54.

once it has started also *increases* the expected net present value[26] of the project, all else equal, according to Pindyck.[27] A hypothetical example shows how this works. Let us assume that a nuclear power plant has a payoff (or discounted revenue stream) that is known and is equal to $4500 per kilowatt of capacity. Suppose that with a probability of 0.5 the cost of building the plant is $2000 per kilowatt of capacity, and with a probability of 0.5 the cost of building the plant is $8000 per kilowatt of capacity. The net present value of the project per kilowatt of capacity is $4500 – (0.5)*$2000 – (0.5)*$8000 = -$500, so the project has a negative expected value, and therefore would not be undertaken at all. However, suppose the developer can spend the $2000 per kilowatt and with a probability of 0.5 the project will be complete, and with a probability of 0.5 the project would require the additional $6000 in outlays. Under the latter scenario, the project would be abandoned. The net present value of the project per kilowatt is then the $2000 per kilowatt outlay plus the probability that no more money will have to be spent times the payoff that would be received. Therefore, the net present value becomes -$2000 + (0.5)*$4500 = +$500, so it pays for the developer to spend the $2000/kW to start the project as it has a positive expected value. Thus, the option to abandon partially limits the impact of technical uncertainty.

Input cost uncertainty is difficult to mitigate or is largely outside the developer's control.[28] In addition to traditional input costs such as land, labor, and materials which may change over the period of construction, Pindyck also includes government regulations promulgated during the project period that might in some way affect construction costs. Uncertainty related to input costs differs from technical uncertainty in that input prices and regulations may change regardless of whether or not a developer goes forward with a nuclear plant project; changes in input costs are likely to be correlated with overall economic activity.[29] These uncertainties grow with the duration of the project's construction phase regardless of whether or not that phase is lengthened due to voluntary or involuntary delays. Moreover, input cost uncertainty cannot be mitigated by starting a project and then learning about the investment requirements, as is the case with technical uncertainty which resolves itself as the project unfolds and construction costs reveal themselves. In the case of input cost uncertainty, the information acquired by starting

26. *Id.* (emphasis added). The "Net Present Value" (NPV) may be defined as "the difference between the present value of cash inflows and the present value of cash outflows over the life of the project. NPV is used in capital budgeting to analyze the profitability of an investment or project." *See* Investopedia, Net Present Value, http://www.investopedia.com/terms/n/npv.asp (last visited May 5, 2008).

27. Pindyck, s*upra* note 20, at 55. The example that follows is closely related to the example used by Pindyck on page 55.

28. *Id.* at 54.

29. *Id.*

the project could be accessed elsewhere because price changes and regulatory changes are independent of whether or not a given project is undertaken. However, the option of waiting to commence with construction of the nuclear plant project is one way to mitigate the input cost uncertainty because developers learn more as regulations and prices evolve. As with the case of technical uncertainty, input cost uncertainty does increase the expected net present value of a project.[30] However, unlike the case of technical uncertainty, the increase in the expected net present value of building a nuclear plant comes from the option to delay construction so that there is more time for input cost and regulatory policy uncertainty to be resolved. Again, a hypothetical example can show how the option to delay increases the project value. Let us assume that the present value of the operating cash flows (payoff) from building a nuclear plant is $4500 per kilowatt of capacity. With a probability of 0.5 the cost of building the plant is $2000 per kilowatt of capacity, and with a probability of 0.5 the cost of building the plant is $6000 per kilowatt of capacity. The expected net present value of the project per kilowatt of capacity is positive at $4500 – (0.5)*$2000 – (0.5)*$6000 = +$500. However, under some circumstances, the project would have a higher expected net present value from waiting. Suppose the developer waits until the input prices are revealed and the cost of construction is known. Assuming an interest rate of zero for ease of presentation, if the cost of construction is $6000 per kilowatt of capacity, the plant will not be built as it has a negative value. But with a probability of 0.5, the cost is $2000 per kilowatt of capacity, and the nuclear plant will be built yielding an expected net present value of (0.5)*($4500 – $2000) = $1250, which is greater than the expected value of not waiting to have the input cost information revealed.

Using some plausible parameterizations, Pindyck finds that input cost uncertainty (including changing regulatory requirements) likely had the greatest impact on the financial feasibility of nuclear plant construction in the 1980s.[31] Thus, even though technical uncertainty influenced nuclear plant cancellations, the role of input costs appears to have been even more important, leading to decisions to delay further nuclear investments.[32] Pindyck's findings are consistent with the casual observation that no plants have been ordered since the 1970s (potential developers are "waiting"), and licensing processes for new nuclear units only have been observed in recent years.[33]

30. *Id.* at 55. The example we cite also follows Pindyck's example, but with different numbers.
31. *Id.* at 70.
32. *Id.*
33. EIA, *supra* note 6. For data on licensing activity by U.S. nuclear plants, *see also* Nuclear Energy Institute, *U.S. Nuclear License Information*, Oct. 2007,

Nuclear plant developers also face post-construction uncertainty as it relates to the operating environment during, and revenues resulting from, commercial operation. The operating environment determines the ability of the project developer to recover the costs of the investment and to obtain a return on that investment. Financing for the new plant will almost inevitably come from debt raised in international markets, to be repaid once electricity is generated; the cost of debt will be dependent upon the risk related to revenue generation and cost recovery.[34] We refer to the uncertainty associated with commercial operation as revenue and operating uncertainty. Pindyck makes brief mention of this type of uncertainty, but spends little time developing or discussing it.[35]

Revenue and operating uncertainty in the commercial operation of nuclear plants stems from a number of sources, including: changes in electricity demand and prices; changes in the prices of fuel and technology for competing coal and natural gas combined cycle technologies; state and federal regulatory and policy changes such as climate change policy, electricity market rules, tax and subsidy policies, and allowed cost recovery rules; availability (and pricing) of transmission links to areas where electricity will be sold;[36] available contractual arrangements for power sales for merchant plants; price levels for cost recovery ultimately allowed under rate of return formulae for regulated utilities; operational risks associated with new technologies and reactor designs that may reduce plant availability and operating hours; indecision regarding the storage of nuclear waste and spent fuel; the treatment of decommissioning costs; and access to the expertise needed to operate new reactors (since no new plant has begun commercial operation in the United States since 1996).[37]

http://www.nei.org/resourcesandstats/documentlibrary/reliableandaffordableenergy/graphicsandcharts/usnuclearplantlicenseinformation/. The most recent plants to begin commercial operation were as follows: Limerick 2 (Jan. 1990); Comanche Peak 1 (Aug. 1990); Seabrook 1 (Aug. 1990); Comanche Peak 2 (Aug. 1993); and, Watts Bar 1 (Feb. 1996). *Id.*

34. Paul Breeze, *The Future of Nuclear Power: Growth Opportunities, Market Risk, and the Impact of Future Technologies*, BUS. INSIGHTS, Mar. 2007, at 91.

35. Pindyck, *supra* note 20, at 53-54. When Pindyck wrote his article, there were no competitive markets for electricity, so all nuclear units operated in a rate-regulated environment. Consequently, Pindyck argued that revenue uncertainty is less significant for investment decisions than technical and input cost uncertainties associated with construction. For rate-regulated utilities, legislation or commission orders authorizing construction work in progress mitigate against revenue uncertainty during construction. Absent that authority, utilities cannot recover their costs. *See infra* Part II (discussing state legislation authorizing cost recovery before a nuclear plant becomes operational).

36. The availability and pricing of transmission is pertinent to both regulated and merchant plants and may affect the project well before it is built. Construction of transmission capacity may become part of the overall project. The availability of adequate transmission capacity will factor into the siting decision for a plant. Plans for merchant plants, particularly nuclear plants with such high construction costs, likely would not be made without contracts for the purchase of energy by major customers.

37. Lacy, *supra* note 16, at 4-5. The last plant constructed in the United States was Watts Bar I in Tennessee which began construction in 1973 but only started to generate power in 1996. *See*

Another example of revenue and operating uncertainty relates to the price of uranium fuel. The spot market price of uranium has been volatile, increasing from below $20 a pound in 2004 to an inflation adjusted price of $138 a pound in July 2007.[38] Some of the fuel price risk can be mitigated through long-term contracts by which most uranium is procured, but higher spot market prices may eventually result in higher contractual prices.[39] There is also some question as to whether mining and enrichment capacity can keep up with future demand.[40] According to one estimate, to meet existing nuclear power generation demand, uranium mining and enrichment capacity would need to be doubled over the next five years.[41] As one article aptly put it, "the potential long-term supply of uranium and plutonium for nuclear fuel is more than sufficient, but the timing and price of these supplies is uncertain."[42] The future demand for uranium in the United States may be eased, at least to some extent, if nuclear reactors in this country were to reprocess spent fuel which is currently the practice or is under development in France, the United Kingdom, Japan, Russia, and India.[43]

Some revenue and operating uncertainty can be controlled and mitigated by the nuclear plant developer, while other uncertainties may be beyond the control of the plant developer. For example, on the operating cost side, the developer can sign long-term contracts for fuel to mitigate uncertainty in uranium prices or can offer to build or help fund transmission facilities necessary to deliver power. On the revenue side, long-term contracts for power sales in a market environment or long-term commitments to sell power to captive customers in a rate-regulated environment can provide some revenue certainty. The actions developers may take to mitigate revenue and operating uncertainty

also Lacy, *supra* note 16 n.33.

38. Edward D. Kee, *Nuclear Fuel: A New Market Dynamic*, 20 THE ELECTRICITY J. 59 (Dec. 2007).

39. *Id.* at 60; *see also* Edward Kee, *Nuclear Fuel Future*, PUB. UTIL. FORTNIGHTLY, Feb. 2008, at 30. In this article, Kee observed the lag between contractual agreements and the incorporation of increased uranium prices in the spot market: "[b]y the time the 2007 increases in uranium spot prices appear in reported nuclear fuel costs and are incorporated into the traditional approach to nuclear fuel cost projections, some decisions about new nuclear plant investments may have been made already." *Id.*

40. The Keystone Center, *supra* note 23, at 38-41. Weighted average prices for uranium increased by 72% from 2003 to 2006. *See also* EIA, *Uranium Purchased by Owners and Operators of U.S. Civilian Nuclear Power Reactors by Origin Country and Delivery Year*, May 16, 2007, http://www.eia.doe.gov/cneaf/nuclear/umar/table3.html.

41. Jim Harding, *Economics of Nuclear Power and Proliferation Risks in a Carbon-Constrained World*, 20 THE ELECTRICITY J. 70 (Dec. 2007).

42. Kee, *supra* note 38, at 58.

43. However, the cost of reprocessing spent fuel may be greater than the cost of directly disposing it. *See Costs of Reprocessing Versus Directly Disposing of Spent Nuclear Fuel: Hearing Before the S. Comm. on Energy and Natural Resources*, 110th Cong. (2007) (statement of Peter R. Orszag, Director, Congressional Budget Office), *available at* http://www.cbo.gov/ftpdocs/88xx/doc8808/11-14-NuclearFuel.htm.

preceding the actual construction and commercial operations of a plant are similar to the mitigation actions developers may take to mitigate both technical and input cost uncertainty associated with construction. Assuming that the cost of constructing a nuclear plant is known, it makes sense for a developer to attempt to execute agreements that provide revenue and operating certainty in advance of construction and commercial operations with the objective of increasing the expected net present value of the project. In other words, there is a value to taking action to reduce uncertainty in a plant's revenue stream and commercial operations, similar to taking action in the case of technical uncertainty to mitigate construction-related uncertainty. Delaying the construction decision itself is a strategy used to mitigate both input cost uncertainty and revenue and operating uncertainty.

Why might developers delay? Uncertainties related to the costs of competing fuels and technologies and future state, federal, or regulatory policies are beyond the control of the nuclear plant developer. Because these uncertainties cannot be mitigated by the developer, there is no benefit in taking action to proceed immediately with construction, but there is a benefit in waiting to see how the uncontrollable uncertainty ultimately resolves itself, especially with respect to evolving state, federal, and regulatory policies that could potentially affect the costs of a plant's commercial operations and post-construction revenue stream. The concept of waiting for more information to mitigate revenue and operating uncertainty before a decision is made to begin construction is similar to that of waiting on the outcome of input cost uncertainty affecting construction costs. Delay of the actual construction of the plant results in an increase in the expected net present value of the project.

The developer's decision-making process can be illustrated with this hypothetical example. Let us assume that the cost of construction is known and is $3000 per kilowatt of capacity. With a probability of 0.5, the realization of input costs for other technologies and policies results in a present discounted value (cash flow) of operating the plant, net of operating costs, which is $2000 per kilowatt of capacity. With a probability of 0.5, the realization of input costs for other technologies and policies results in a present discounted value of operating the plant, net of operating costs, which is $6000 per kilowatt of capacity. The expected net present value of the nuclear plant is then (0.5)*$2000 + (0.5)*$6000 - $3000 = $1000 per kilowatt of capacity (the present value of expected net operating cash flows minus the PV of construction costs). Suppose instead that the developer can either attempt to sign contracts for power sales that ensures the present discounted value of operating the plant, net of operating costs, to be $6000, but that only has a 0.5 probability of success. Alternatively, the developer can simply wait until there is more information on input prices and regulatory policies. However, if no long-term contracts are signed, the project does not go forward, because expected cash flows from operating the plant would be only $2000 per kilowatt of capacity compared with the $3000 construction cost/kW. The expected net present value of the project, with the possibility of signing contracts, is now (0.5)($6000 - $3000) = $1500 per kilowatt of capacity, which makes the action of signing a contract before going forward more valuable than building the nuclear plant with uncertainties about revenue and operating costs. The same logic applies to simply waiting for the realization of the input price or policy outcomes.

In summary, the way in which potential nuclear plant developers can mitigate the risk associated with uncertainty is to begin the project but retain the option of abandoning the project if it appears the costs to complete construction are too high, as in the case of technical uncertainty associated with construction. Alternatively, developers may decide to delay construction to wait for updated information or for uncertainties to be narrowed or resolved, as in the case of input cost uncertainty associated with construction and revenue and operating uncertainty associated with commercial operation. Delay in plant construction essentially has an "option value:"[44] developers gain additional information about the environment and can narrow the range of uncertainty, especially uncertainty associated with new technologies. Delaying construction can allow developers to learn from "first-movers" as they go through untested regulatory siting and permitting processes, work out technical issues with equipment manufacturers, and identify construction techniques that are cost-effective. Delay also permits developers to gain this valuable information at (relatively) low cost.

II. COST RECOVERY TREATMENT FOR NUCLEAR POWER GENERATION

Cost recovery for nuclear power projects is one of the biggest obstacles facing utilities and merchant developers. In this part, we are concerned with two issues: (1) the standards that underpin cost recovery; and, (2) the assumptions used to develop projected costs.

44. The term "option value" is derived from the real-options theory of investment that received extensive treatment in a publication by Avinash K. Dixit and Robert Pindyck, INVESTMENT UNDER UNCERTAINTY (Princeton University Press 1994). According to one explanation for the real-options theory, conditions change based on the emergence of new information. However, as long as there is an option to invest, the option retains an economic value that can be priced and has value. *See* Luke Reedman et al., *Using a Real-Option Approach to Model Technology Adoption Under Carbon Price Uncertainty: An Application to the Australian Electricity Generation Sector*, THE ECON. RECORD 82 (Special Issue) S64, S65 (2006).

A. Cost Recovery Standards

A recent study by the National Council on Electricity Policy identifies regulatory policy as one of the four major sources of uncertainty facing utilities.[45] It is a major source of what we refer to as "revenue and operating uncertainty" in this context. A major component of regulatory policy is the treatment of cost recovery for utility plant investments. For utilities, the treatment of cost recovery resides with regulatory commissions. Statutory language specifies the performance expected of utilities.[46] Although most regulatory standards call for "just and reasonable" performance, the term "just and reasonable" could be construed differently.[47] Three court cases illustrate differing interpretations of desired performance. In a case dealing with the appropriate computation of tax rates to be charged California end use customers of natural gas, the Fifth Circuit Court of Appeals, in *El Paso Natural Gas Co. v. FPC,* expanded on its philosophy of the "just and reasonable" rate standard by observing that "it is the obligation of all regulated public utilities to operate with all reasonable economies."[48] In a case that dealt with a managerial decision to select straight-line depreciation over the liberalized version of depreciation, the Seventh Circuit Court of Appeals in *Midwestern Gas Transmission Co. v. FPC,* concluded that federal intervention might be warranted following the required hearing and review procedures if "elected tax policies do not fairly indicate a reasonable and prudent business expense."[49] In *Potomac Electric Power Co. v. Public Service Commission,* the utility appealed a decision of the Public Service Commission of the District of Columbia that disallowed twenty-five percent of the utility's Demand Side Management program expenditures. In its review of the commission's testimony, the Court of Appeals noted the commission's finding that the

45. NATIONAL COUNCIL ON ELECTRICITY POLICY, STATE POLICIES FOR FINANCING ELECTRICITY RESOURCES, VOLUME 1: PAYING FOR POWER PLANTS IN RESTRUCTURED STATES 28 (2007), http://ncouncil.org/pdfs/pubs/FINALPayingPowerPlants.pdf.

46. States also can reduce uncertainty over the ratemaking principles to be used in cost recovery proceedings by providing for a determination of ratemaking principles prior to the undertaking of plant construction. For example, Iowa Code section 476.53 requires the Iowa Utilities Board to issue an order, after a contested case hearing, on the ratemaking principles that will apply to base load generating plants (including nuclear power) and transmission facilities. IOWA CODE ANN. § 476.53 (West 2008) Kansas Statute section 66-1239 (2007) requires the Kansas Corporation Commission to issue an order delineating its ratemaking principles and treatment of costs during the useful life of a generating plant (including nuclear power) and for transmission facilities. KAN STAT. § 66-1239 (2007).

47. We are indebted to Scott Hempling, Director, National Regulatory Research Institute, for his analysis of case law pertaining to nuclear generation. *See* Scott Hempling, *Evaluating Nuclear Generation: Is Objectivity Impeded by Uncertainties in the Principles and Institutions of U.S. Utility Regulation?* (Nov. 2006) (on file with author at shempling@nrri.org).

48. El Paso Natural Gas Co. v. FPC, 281 F.2d 567, 573 (5th Cir.), *cert. denied*, 366 U.S. 912 (1960).

49. Midwestern Gas Transmission Co. v. Federal Power Commission, 388 F.2d 444 (7th Cir. 1968).

company "had failed to supply information that the Demand Side Management programs were implemented at the lowest feasible cost."[50] So in this context, prudently incurred expenses equated to "lowest feasible cost." [51] Regulatory interpretations as to whether those standards have been met and, if not, who bears the risk pose significant input cost uncertainties to utilities contemplating new nuclear power plants.

Regulators may be required by statute to apply a "used and useful" test to cost recovery: this test is always applied in hindsight. If cost recovery is based on a used and useful test, the utility and its shareholders bear the risk if the investment decision turns out poorly and is disallowed. However, customers do assume a part of that risk through a higher cost of capital to compensate for the potential of capital cost disallowance even if the utility is allowed to recover its costs. In contrast to the hindsight nature of the used and useful test, a prudent-investment test gives a utility the opportunity to recover its investments through regulated rates based on information available to the utility at the time of the project decision regardless of future developments. If the company realizes a good outcome, its customers will benefit, but if that is not the case and the decision was deemed prudent at the time, customers will assume the downside risk.

Neither approach is inherently better than the other, according to a paper by Baumol and Sidak.[52] The difference really lies in who bears the risk of the investment. Baumol and Sidak consider the worst case scenario to be a combination of the hindsight and foresight tests: the utility is prevented from earning adequate revenues whenever the outcome is not realized and is constrained from profiting when performance is outstanding.[53] ("Heads I win; tails you lose.") Perhaps the best example of this hybrid approach can be found in second guessing through the regulator's application of economic used and useful tests. The hybrid approach compares the current or projected cost of the project to the current or projected market value and not to the market value that was projected at the time the regulatory commission approved a determination of need for the plant. Many years and changing market conditions can elapse between a commission's approval of a project and completion of plant construction. Regulatory policies based on that approach permit costs to be disallowed in the future in response to changing market conditions that would appear to make a utility's project

50. Potomac Electric Power Co. v. Public Service Commission, 661 A.2d 131, 137-38 (D.C. App. 1995).

51. *Id.*

52. William J. Baumol & J. Gregory Sidak, *The Pig in the Python: Is Lumpy Capacity Investment Used and Useful?*, 23 ENERGY L.J. 383, 391-92 (2002).

53. *Id.* at 392.

decisions uneconomical in retrospect. Management's decision would be substituted for *ex-post* regulatory judgment about future plant costs but without supporting market data.[54]

Three regulatory decisions that illustrate the tests' application using the hybrid approach include: the Kansas Corporation Commission's first Wolf Creek Decision in 1985, the Massachusetts Department of Public Utilities' cost recovery treatment of Millstone 3 Nuclear Facility in 1986, and the Montana Department of Public Service Regulation's treatment of the Colstrip 3 coal-fired generating station in 1984.[55] The primary effect of the hybrid approach is that the utility and its shareholders assume the risk of bad outcomes but do not profit from good outcomes. This hybrid approach raised constitutional questions in the United States Supreme Court decision, *Duquesne Light Co. v. Barasch*, although the decision to determine the appropriate rate-setting methodology was expressly left to the states, and considerable flexibility was accorded them to that end.[56]

Merchant developers always assume the risk of the market which rewards or punishes them for their investments on the basis of hindsight.[57] Following the Enron debacle and likely in response to the international financial markets' reactions to it, merchant developers, such as AES, Williams, Calpine, El Paso, Mirant, Reliant, and Dynegy, experienced extensive stock value losses and credit rating reductions.[58] The U.S. electricity sector also experienced a seventy percent decrease in new bank financing and bond financing of projects between 2001 and 2002 in the wake of Enron's collapse and the California crisis.[59]

The situation for many merchant developers has improved since that time. Standard & Poor's attributed the mix of strategies—asset sales, equity issuance, and debt refinancing—to their success in reducing debt (on the balance sheet) and interest burdens (reflected in income statements). Other mitigating strategies included divestiture of volatile trading operations and tolling agreements[60] that proved unprofitable. In the long term, Standard & Poor's expects the merchant developers to

54. Jonathan Lesser, *The Used and Useful Test: Implications for A Restructured Electric Market*, 23 ENERGY L.J. 349 (2002).

55. *Id.* at 360-62. The Montana District Court overturned the decision of the Department of Public Service Regulation citing problems with the use of the marketplace standard for cost recovery.

56. Duquesne Light Co. v. Barasch, 488 U.S. 299, 313-15 (1989).

57. Baumol & Sidak, *supra* note 52, at 391.

58. The stock market values of these companies fell 90-95% between the spring of 2001 and the spring of 2003, and their credit ratings were downgraded to between BB- and B-. *See* FRANCOIS LEVEQUE, COMPETITIVE ELECTRICITY MARKETS AND SUSTAINABILITY 77 (Edward Elgar ed. 2006).

59. *Id.*

60. Tolling agreements operate as follows: An owner, such as an Independent Power Producer (IPP), leases a plant to a lessee, such as a utility. The IPP operates the plant but must follow the utility's instructions for dispatching the unit to generate electricity.

perform well, assuming they have achieved economies of scale and have diversified their generation portfolios in terms of both fuel and geographic representation.[61] According to Standard & Poor's, higher commodity prices (directly affecting fuel costs for competing technologies) have contributed to more favorable opportunities for new nuclear power projects, but waste disposal and safety issues continue to pose significant risks to investors.[62] The waste disposal obstacle could be even more pronounced in states that have laws requiring regulatory commissions to make findings regarding the potential disposition of spent nuclear fuel. Although the wording in their laws varies considerably, eleven states have such requirements.[63]

Regulated electric utilities, like Florida Power & Light (FPL) Company, an investor-owned utility serving approximately eight million Floridians, also may benefit from a lower cost of capital for new power plant construction if the parent company has a diversified energy portfolio that contributes to a higher credit rating. For example, the FPL Group has taken the lead in the nation in developing wind-power which has brought it success on the stock market. The company reported forty-eight wind farms in sixteen states and plans for tripling its capacity from wind power through a $20 billion investment.[64] The FPL Group, through its subsidiary FPL Energy, also owns interest in and operates three nuclear plants in regions of the country where there is wholesale competition—the Duane Arnold nuclear power station in Iowa, Point Beach in Wisconsin, and Seabrook in New Hampshire. Diversified energy portfolios may improve the chances of merchant developers and utilities for obtaining needed capital for their nuclear power construction projects. But states also can offset some of the risk associated with technical uncertainty present in constructing nuclear power plants and revenue and operating uncertainty, at least for regulated utilities, by explicitly stating in statute what types of costs would be considered in cost recovery proceedings applied to "used and useful" and "prudent" investments. For example, Florida, Louisiana, Kansas, and North Carolina authorize utilities to earn a return on "construction work in progress" in the rate base before a new nuclear plant is brought on line.

61. CHRISTOPHER MUIR, STANDARD & POOR'S, NRG ENERGY INC., SUB-INDUSTRY OUTLOOK, STOCK REPORT, Feb. 9, 2008, http://reports.standardandpoors.com/data/EQ/pdf/sr/6/62937750.pdf (Subscription required).

62. *Id.*

63. David Lovell, *State Laws Limiting the Construction of New Nuclear Power Plants*, Wisconsin Legislative Council Staff Memorandum, Nov. 29, 2006, *available at* http://www.legis.state.wi.us/lc/committees/study/2006/NPOWR/files/memo2_npowr.pdf. These states include: California, Connecticut, Illinois, Kentucky, Massachusetts, Maine, Montana, New Jersey, Oregon, West Virginia, and Wisconsin.

64. Standard & Poor's, *FPL Grabs the Lead in Renewable Power*, Oct. 18, 2007, http://www.businessweek.com/print/investor/content/oct2007/pi20071017_709986.htm.

Florida's legislation and rule authorizes a utility to recover actual and projected preconstruction costs before the plant becomes operational.[65]

"Preconstruction costs" are defined in Florida's rule as "costs that are expended after a site has been selected in preparation for the construction of a nuclear power plant, incurred up to and including the date the utility completes site clearing work."[66] A utility that ultimately abandons construction of a new nuclear power plant also is expressly authorized to recover all prudent preconstruction and construction costs following a final order issued by the Florida Public Service Commission on a determination of need.[67] Moreover, in its rule, the Commission explicitly states that preconstruction costs found to be reasonable and prudent cannot be disallowed or subject to further prudence review.[68] Obviously, the Commission has discretion in its interpretation of prudency, as supported by case-law on the matter, but this statutory and regulatory language prevents the Commission from indulging in the constitutionally questionable hybrid approach of foresight and hindsight to ratemaking discussed above once prudency has been determined.

State legislation authorizing construction work in progress for prudently incurred expenses without being subject to further review may mitigate technical uncertainty as well as revenue and operating uncertainty. Such a rule allows a regulated developer to go forward and begin a project and then abandon the project if it is determined that the project is too expensive to complete or if projections of the future operating environment no longer make the project least-cost relative to other options. However, statutes and rules may not be sufficiently prescriptive to anticipate all the carrying costs incurred by utilities, especially those related to the rising costs of inputs and material for the project in cost recovery proceedings, so some level of input cost uncertainty will remain. Utilities in other states might decide to delay construction plans in rate-regulated markets until there is more information about the nature of the costs deemed by regulators to be reasonable and prudent and those costs that have been disallowed.

B. Assumptions for Construction Cost Projections

Comparisons of cost projections of nuclear power generation with new generation from other energy sources involve multiple assumptions. Two studies undertaken in the United States on comparative costs are the

65. FLA. STAT. § 366.93 (2007) (Cost recovery for the siting, design, licensing, and construction of nuclear power plants); FLORIDA RULEs R. 25-6.0423 – Nuclear Power Plant Cost Recovery.

66. FLORIDA RULES R. 25-6.0423(2)(e).

67. FLA. STAT. § 366.93(6) (2007).

68. FLORIDA RULES R. 25-6.0423(5)(a)(2).

MIT report, *The Future of Nuclear Power: An Interdisciplinary MIT Study* (2003)[69] and the University of Chicago's report, *The Economic Future of Nuclear Power* (2004).[70] We note that both studies predated the passage of the Energy Policy Act of 2005 (EPACT 2005), and several years have elapsed since they were completed.

The MIT report compared the levelized cost of a nuclear power plant to that of new plants using pulverized coal and new combined cycle natural gas-powered plants.[71] The study assumes an overnight capital cost of $2000/kW based on estimates from the EIA and recent construction experience, rather than the more expensive capital costs seen from nuclear plants going into operation during the 1980s and 1990s.[72] According to the study, generation from nuclear power is not cost competitive even when natural gas is priced over the lifetime of the combined cycle plant at a levelized price of $6.72 per thousand cubic feet, the highest of three cost scenarios used in the report for natural gas.[73] Reducing the construction costs by twenty-five percent and the construction time from five to four years fails to make nuclear power generation competitive with coal but makes it slightly more competitive with the highest cost scenario for natural gas.[74] Nuclear power only begins to compete with coal and gas under two scenarios: first, when construction can be financed at a weighted average cost of capital equal to that of coal and gas plants[75] and second, when the cost of carbon emissions is internalized through a carbon reduction tax or cap-and-trade policy at approximately $100/ton carbon charge even without further construction cost reductions.[76]

The University of Chicago report also compares the levelized cost of

69. MASSACHUSETTS INSTITUTE OF TECHNOLOGY, THE FUTURE OF NUCLEAR POWER: AN INTERDISCIPLINARY MIT STUDY (2003), http://web.mit.edu/nuclearpower/pdf/nuclearpower-full.pdf [hereinafter MIT STUDY].

70. UNIVERSITY OF CHICAGO, THE ECONOMIC FUTURE OF NUCLEAR POWER: A STUDY CONDUCTED AT THE UNIVERSITY OF CHICAGO (2004), http://www.anl.gov/Special_Reports/NuclEconAug04.pdf [hereinafter UNIVERSITY OF CHICAGO STUDY].

71. MIT STUDY, *supra* note 69. Levelized costs, otherwise known as busbar costs, typically include capital, interest during construction, operation and maintenance, additional incremental capital expenditures, fuel, waste disposal, and decommissioning costs.

72. *Id.* at 39-40. The capital costs are expressed in 2002 dollars. Cost estimates appear to have increased since the MIT study was released in 2003. *Id.* For example, Constellation projects costs for a new nuclear unit at Calvert Cliffs in Maryland to exceed $3,000/ installed kW. *See* Margaret Ryan, *Constellation, PPL CEOs Say Nuclear Loan Guarantees Critical*, PLATTS ELEC. POWER DAILY, Feb. 6, 2008. For recent estimates on building new nuclear plants in Texas and Florida, *see also* Rebecca Smith, *New Wave of Nuclear Plants Faces High Costs*, WALL ST. J., May 12, 2008, at B.1, B.4.

73. MIT STUDY, *supra* note 69, at 40-41.

74. *Id.* at 41.

75. *Id.* at 42.

76. *Id.* However, nuclear power would still be more costly than natural gas except in the high cost scenario in which gas is $6.72 per thousand cubic feet. The $100/ton carbon charge is equivalent to approximately $27.30/ton of carbon dioxide.

nuclear power plants to that of plants with coal-fired or gas-fired generation.[77] In examining various studies on the cost of nuclear power compared to coal and natural gas technologies, nuclear is only cost competitive at capital costs below $1500/kW.[78] Like the MIT study, the University of Chicago report also points out the large cost impact of delays in construction, and the additional costs of financing at a weighted average cost of capital well above the cost of capital for coal and gas technologies.[79] The study concludes that new nuclear power plants become more competitive through loan guarantees, accelerated depreciation, investment tax credits, and production tax credits.[80] They also become competitive with coal-fired and natural gas-fired plants as more plants come on line, the assumption being that the cost of nuclear power will come down as the learning curve goes up with design improvements and as companies learn from the prior experiences of the "pioneers."[81] As in the MIT study, this report finds nuclear power to be cost competitive if a stringent carbon reduction policy is adopted.[82]

At the time of writing, we do not know what form a national climate policy will take or even if one will be adopted. However, a more stringent policy in terms of either higher required reductions in emissions from a cap and trade approach or a higher carbon reduction tax will confer a greater advantage to generators that emit a lower level of greenhouse gases.[83] A study by Koomey and Hultman (2007) used the MIT study and the University of Chicago study to project costs of new nuclear facilities using advanced technology (Generation IV reactors) and compared the projected costs to the historical levelized costs for ninety-nine reactors in the United States.[84] The authors conclude that the projected levelized costs of the new reactors with favorable regulation are at or below the costs of the cheapest reactors in the historical sample spanning 1970-2005. Nonetheless, significant problems remain that could affect projections despite standardized reactor designs, streamlined licensing procedures, and sophisticated construction management techniques. These include "the interlinked issues of reactor scale, customization of site-built technologies, slow electricity demand growth, intense competition from other energy sources, deregulated electricity markets, slow speed of industry learning, nuclear waste disposal,

77. UNIVERSITY OF CHICAGO STUDY, *supra* note 70.

78. *Id.* at 1-8 tbl.1-1. Capital costs ranged from just over $1000/kW to $2000/kW in 2003 dollars. These cost differences reflect different types of nuclear technologies.

79. *Id.* at 3-17 tbl.3-6.

80. *Id.* at 9-18.

81. *Id.* at 9-19.

82. *Id.* at 9-18.

83. The Keystone Center, *supra* note 23, at 28.

84. Jonathan Koomey & Nathan Hultman, *A Reactor-level Analysis of Busbar Costs for US Nuclear Plants, 1970-2005*, 35 ENERGY POL'Y 5630-42 (2007).

terrorism, and proliferation."[85]

The question of unexpected costs for energy technologies also bears discussion because confidence in assumptions used for cost projections is critical for reducing the technical cost uncertainties that Pindyck referenced. It is beyond the scope of this paper to explain how such costs should be modeled and which methodologies are most appropriate for capturing uncertainties associated with new technological innovations. However, there are great perils in excluding from cost projections for new nuclear plants any insights gained from an analysis of highly skewed cost distributions of reactors once they are operational. This kind of historical analysis can shed some light on the implications of extreme outlier costs; prudent policy would be to incorporate the risk of cost surprises into future planning.[86]

Of course, we might expect the use of turnkey reactor units and experienced construction engineers to lower that risk to some extent in future years.[87] Historical analysis of this sort is and will continue to be more complicated for reactors operating in a restructured environment (like Texas) where rules governing data disclosure are much less stringent.[88] Sounder assumptions underlying cost projections for the new generation of nuclear power plants should certainly offset some of the technical cost uncertainties affecting future investment decisions. Cost projections should also internalize environmental and security costs and reflect explicitly public subsidies to nuclear power, like those included in EPACT 2005.[89]

III. DIFFERENCES AND COMMONALITIES – TEXAS AND FLORIDA

The type of regulatory environment in which a plant operates affects the expected net present value of investments and the degree of revenue and operating uncertainty prospective developers will face. The following question arises: are developers better positioned to recover costs and make a profit on a new plant that is subject to traditional rate regulation or one that is operating in wholesale markets where prices are

85. *Id.* at 5640.

86. Nathan Hultman & Jonathan Koomey, *The Risk of Surprise in Energy Technology Costs*, 2 ENVTL. RES. LETT. 1-6 (2007); *see also* Nathan Hultman et al., *What History Can Teach Us About the Future Costs of U.S. Nuclear Power*, ENVTL. SCIENCE & TECH., Apr. 1, 2007.

87. Selection of a proven technology and a known engineering firm to design and construct the plant is a strategy for risk mitigation. For example, NRG Energy, Inc. chose the Advanced Boiler Water Reactor which was certified by the NRC for construction of new units in Texas with the company, Toshiba, as the engineer. Toshiba built a generating unit for Tokyo Electric Power Co. in 39 months. *See* Scott Gawlicki, *Financing New Nukes*, PUB. UTIL. FORTNIGHTLY, Feb. 2008, at 20.

88. Koomey & Hultman, *supra* note 84, at 5639.

89. Hultman et al., *supra* note 86, at 2092.

unregulated and allowed to reflect market conditions? There is a risk/reward trade-off between building plants in a traditional rate-regulated environment and a wholesale-market environment. Developers of traditionally regulated generating plants have more limited opportunity in terms of up-side profit but arguably less risk for losses, and merchant developers have greater opportunity for profits but also greater risk for losses, all else equal.[90] To further complicate matters, the requirements affecting generating plant construction subject to traditional rate regulation and the competitive market also can add or reduce uncertainty as we further explain below.

We selected Texas and Florida for comparative analysis for the following reasons. Texas is a largely restructured state with price-deregulated generation subject to market power mitigation measures in most of its regions. A restructured market increases revenue and operating uncertainty for developers because there is no regulatory framework to lend more predictability to cost recovery. Texas has a competitive wholesale electricity market and retail competition. Texas commenced its retail restructuring effort in January 2002. Retail choice was offered to residential, commercial, and industrial customers. As of September 2007, 40% of residential customers, 47.5% of commercial customers, and almost 64% of large industrial customers had switched to a non-affiliated power provider.[91] Unlike some states, Texas did not require utilities to divest themselves of generation capacity but only to make their generation facilities affiliates.[92] Florida, in contrast to Texas, has not restructured its electric industry: generation is a part of the vertically integrated utility service. Retail customers have no choice in energy provider and pay for generation as part of their overall monthly utility bills. Florida, as a non-restructured state, will add generation capacity through regulated utility plant investment. Florida's statutes and case law have been arguably more conducive to the construction of regulated generating plants than of merchant plants.[93] Merchant

90. Lacy, *supra* note 16, at 2. A "merchant" plant in Lacy's article refers to any nuclear power generating plant that sells electricity wholesale at market-based rates or under contract to other electric utilities and is not subject to cost-of-service regulation. *See id.* at 2.

91. Public Utility Commission of Texas, *Report Cards on Retail Competition and Summary of Market Share Data*, *Summary of Performance Measure Data*, http://www.puc.state.tx.us/electric/reports/RptCard/index.cfm (last visited May 5, 2008).

92. Pursuant to section 39.051(b) of the Texas Utilities Code, electric utilities were required no later than January 1, 2002, to unbundle their business activities into generation, retail, and transmission and distribution. TEX. UTIL. CODE ANN. § 39.051(b) (Vernon 2007). Pursuant to section 39.051(c), this separation could take the form of separate unaffiliated or separate affiliated companies. § 39.051(c). An affiliated company for generation could be a separate division within the electric utility provided that division, in accordance with section 39.051(d), separated its personnel, flow of information, functions, and operations. § 39.051(d) Utilities are also required to abide by provisions in section 39.157(d). TEX. UTIL. CODE ANN. § 39.157(d) (Vernon 2007).

93. This argument was made by W. Christopher Browder, Gray, Harris & Robinson, P.A.

developers even have been dissuaded from considering new power plant construction in Florida in the aftermath of the Florida Supreme Court's decision in *Tampa Electric Co. v. Garcia*.[94] To date, Florida's siting act has not been amended to include merchant plants, so we expect construction of new generation to come from jurisdictional utilities or other authorized entities unless the statute is revised.[95]

Texas, as a largely restructured state, will add generation capacity through merchant plant investments. Merchant plants have no service area and therefore no captive customer base. Merchant plants accounted for 76.4% of Texas' net generation and 75.2% of Texas' generating capacity in 2006[96] but for only 10.6% of Florida's net generation and 15.1% of the state's generating capacity in 2006.[97] Texas currently has two operating nuclear power plants (four units) licensed by the NRC.[98] Texas leads the nation in the number of expected new nuclear power plants with eight units under consideration at the time of writing. Four merchant developers—NRG Energy, Inc., Constellation Energy Group, Inc., Exelon Corp., and Energy Future Holdings Corp.—are planning to build two nuclear power units apiece in the state. As rate deregulated companies, these developers will not be able to transfer the risk of construction to ratepayers.[99] An article in *The Wall Street Journal* aptly

Merchant Power Battles for Florida Turf, Electric Light & Power, http://uaelp.pennnet.com/articles/article_display.cfm?article_id=74391. This article predated the Florida Supreme Court's decision in *Tampa Electric Co. v. Garcia* 767 So.2d 428 (2000). *See infra* Part 2.

94. 767 So.2d 428 (Fla. 2000). The court reversed a decision by the Florida Public Service Commission which had granted Duke Energy a determination of need under the Florida Electrical Power Plant Siting Act to build and operate a new natural gas-fired combined cycle plant in New Smyrna Beach, Florida. The Supreme Court's reasoning was that the applicant, Duke Energy, was not a jurisdictional Florida entity.

95. The Florida Electrical Power Plant Siting Act is codified as FLA. STAT. § 403.503 (2007). For purposes of the Siting Act, an "electric utility" means cities and towns, counties, public utility districts, regulated electric companies, electric cooperatives, and joint operating agencies, or combinations thereof, engaged in, or authorized to engage in, the business of generating, transmitting, or distributing electric energy. § 403.503(14). Power plants subject to provisions of the Act include: any steam or solar electrical generating facility using any process or fuel, including nuclear materials, except that this term does not include any steam or solar electrical generating facility of less than 75 megawatts in capacity unless the applicant for such a facility elects to apply for certification under this act. § 403.503(13).

96. ENERGY INFO. ADMIN., STATE ELECTRICITY PROFILES, ELECTRIC POWER INDUSTRY GENERATION BY PRIMARY ENERGY SOURCE, 1990 THROUGH 2006 (MEGAWATTHOURS) (TEXAS) 217 tbl.5 (net generation), 218 tbl.4 (net summer capacity) (2007), http://www.eia.doe.gov/cneaf/electricity/st_profiles/sep2006.pdf.

97. *Id.* at 47 tbl.4, 48 tbl.5. Merchant generation capacity is secured in Florida only through long-term contracts.

98. These include Comanche Peak (Units One and Two) and South Texas Project (Units One and Two). No reactors are in the process of decommissioning. *See* U.S. Nuclear Regulatory Commission (NRC) - Texas, http://www.nrc.gov/info-finder/region-state/texas.html (last visited May 5, 2008).

99. Merchant plants in Texas are defined as "power generation companies" pursuant to the Public Utility Regulatory Act, codified at TEX. UTILITIES CODE ANN. § 31.002(10) (Vernon 2007). Merchant plants are required to register with the Public Utility Commission of Texas but are not required to obtain a certificate of need, and must also comply with all the regulations of

described this risk to merchant developers as follows: "Because they have no one to whom to pass along the costs, the merchant operators must cover expenses and make a profit as a result of open-market power sales. If they guess wrong, shareholders will be hurt."[100] Merchant developers also can mitigate their revenue and operating uncertainty to some extent by selling electricity contractually to customers who think they can benefit more from contractual arrangements than from the spot market.

Florida currently has three operating nuclear power plants (five units) licensed by the NRC.[101] In Florida, two electric utilities are planning to build new nuclear power plants. Progress Energy owns Progress Energy Florida, an investor-owned utility serving almost 1.6 million customers in Florida. Progress Energy reported plans to build two units on a 3,000 acre tract of land in Levy County, Florida in close proximity to another nuclear plant it owns.[102] FPL plans to build two new reactors at one of its nuclear plant sites near Miami and to expand capacity at two existing plants. In contrast to shareholders of the Texas merchant developers, Progress Energy and FPL shareholders can be assured at least some opportunity of shifting costs associated with the construction risk to consumers, including costs incurred before the plant actually begins generating power. However, unlike merchant developers in Texas, Progress Energy and FPL must demonstrate to the state regulator, in addition to investors, that the plant is needed; cost recovery also will hinge on the regulator's determination that the costs were prudently incurred.

The type of regulatory framework in a state makes a difference in terms of potential risk exposure—both on the upside and the downside. However, other factors likewise affect developers' risk assessments, including costs of competing fuels, the condition of a state's and region's transmission facilities, projected demand, projected reserve margins, state experience with nuclear power plants, and perceived public support. We discuss each of these factors briefly below:

ERCOT. § 31.002.

100. Rebecca Smith, *Nuclear Energy's Second Act?*, WALL ST. J., Sept. 25, 2007, at B1-2.

101. These are Crystal River (Unit Three), St. Lucie (Units One and Two), and Turkey Point (Units Three and Four). A reactor is in the process of decommissioning at Eglin Air Force Base. *See* U.S. NRC - Florida, http://www.nrc.gov/info-finder/region-state/florida.html (last visited May 5, 2008).

102. According to the company's Web site, "Progress Energy, headquartered in Raleigh, N.C., is a Fortune 250 energy company with more than 21,000 megawatts of generation capacity and $10 billion in annual revenues. The company's holdings include two electric utilities serving approximately 3.1 million customers in North Carolina, South Carolina, and Florida." Progress Energy, http://www.progress-energy.com/aboutus/index.asp (last visited Apr. 16, 2008).

A. Energy Portfolios

Prospective developers care about projected fuel prices for other generation sources because those fuel costs represent a significant source of revenue and operating uncertainty going forward. In a regulated market, long-term assumptions about fuel price are used to determine whether a nuclear project is the least-cost option. Consequently, going forward with the nuclear project would be deemed reasonable and prudent, if that is a public service commission's determination, and the costs associated with the project could be recovered from ratepayers regardless of the actual fuel prices ultimately realized once the plant becomes operational. In a restructured market, there is no possibility for any such regulatory assurance, and the actual revenue stream from power sold must be adequate to recover costs.

Investments in nuclear power facilities look more promising if there is a perception that the competing fuels for generation in a given state will be high-cost when the plant comes on line. This is because the cost of building nuclear plants is much higher than that of other plants, and capital costs must be part of a prospective developer's cost calculus. However, once the plant is built, the marginal cost of nuclear power generation is less expensive.[103] Natural gas prices have been extremely volatile in recent years, and coal prices are likely to be less attractive in the future if a national policy is adopted with the objective of reducing carbon emissions. The mix of generation capacity in both Texas and Florida is different, but both states are heavily dependent on natural gas-fired plants, with nuclear energy comprising a much smaller segment of overall capacity. In 2006, natural gas accounted for 42.9% of Florida's net generation and 49.0% of Texas' net generation; nuclear power accounted for a proportionately higher percentage of Florida's net generation (14.0%) than that of Texas (10.3%); coal constituted a lower percentage of net generation in Florida (29.2%) than in Texas (36.5%); and Florida also had 10.3% of its net generation in oil compared to almost none in Texas.[104]

Texas leads the nation in wind capacity, with 2,370 megawatts of installed wind compared to 2,323 megawatts in California.[105] Wind generation production in Florida is negligible. Texas adopted renewable

103. ENERGY INFO. ADMIN., ASSUMPTIONS TO THE ANNUAL ENERGY OUTLOOK 2007, COST AND PERFORMANCE CHARACTERISTICS OF NEW CENTRAL STATION ELECTRICITY GENERATING TECHNOLOGIES tbl.39 (2007), http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf#page=3.

104. Derived from EIA, *supra* note 96, at 48 tbl.5 (Florida) and EIA, *supra* note 96, at 218 (Texas).

105. ERCOT, 2006 ANNUAL REPORT 9 (2007), http://www.ercot.com/news/presentations/2007/2006_Annual_Report.pdf.

portfolio standards (RPS), and Florida has none.[106] However, Texas' RPS statute and related rule do not include nuclear power.[107] These standards are factors to the extent that they influence the fuel mix for energy sold within a state but, with the possible exception of hydropower, most of the affected power (wind and solar) is not sufficiently reliable for base load generation.[108]

B. Transmission Facilities

Access to reliable transmission facilities is essential for carrying power between generation sources and load centers. To the extent that adequate transmission facilities cannot be arranged in the planning stages of a project, transmission becomes a source of revenue and operating uncertainty that threatens to make a nuclear plant financially non-viable. Both Texas and Florida are rather insular in terms of transmission interconnections.[109] Each state is largely but not entirely confined to a single reliability council that oversees the reliability and security of bulk power (generation and transmission) within the council's jurisdictional

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106. Renewable portfolio standards require electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date. Twenty-four states including Texas have such policies. For more information, see U.S. Department of Energy, *Energy Efficiency and Renewable Energy*, June 2007, at http://www.eere.energy.gov/states/maps/renewable_portfolio_states.cfm.

107. Renewable energy resources subject to RPS are defined in section 39.904 of the Texas Utilities Code. In this section, "renewable energy technology" is defined as

> any technology that exclusively relies on an energy source that is naturally regenerated over a short time and derived directly from the sun, indirectly from the sun, or from moving water or other natural movements and mechanisms of the environment. Renewable energy technologies include those that rely on energy derived directly from the sun, on wind, geothermal, hydroelectric, wave, or tidal energy, or on biomass or biomass-based waste products, including landfill gas. A renewable energy technology does not rely on energy resources derived from fossil fuels, waste products from fossil fuels, or waste products from inorganic sources.

TEX. UTILITIES CODE ANN. § 39.904(d) (Vernon 2007).; *see also* Pub. Util. Comm'n of Tex. Rule § 25.173 (Aug. 2007).

108. The U.S. Department of Energy reported that installed wind capacity in the United States totaled 11,603 MW in 2006 compared to a total installed capacity of 1,075,677 MW from all energy sources. Installed capacity for wind is only 1% of installed capacity from all sources. For data on total installed capacity (all sources), see EIA, *Existing Capacity by Energy Source: Electric Power Annual with data for 2006* tbl.2.2, Oct. 2007, http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html. For data on installed wind capacity, *see* U.S. Department of Energy, Energy Efficiency and Renewable Energy, Wind & Hydropower Technologies Program, http://www1.eere.energy.gov/windandhydro (last visited May 5, 2008). Despite their potentially small contribution to base load capacity, renewable resources are garnering growing attention from both the federal and state government, largely due to concerns with greenhouse gas emissions and the volatile prices of natural gas and oil to meet peak demand.

109. Florida's transmission lines are interconnected to Georgia with 3,600 MW of maximum import capability. These lines were constructed by Florida Power & Light and JEA to connect Southern Company to Peninsular Florida and the east coast of Florida to Miami. *See* FLA. PUB. SERV. COMM'N, REPORT ON TRANSMISSION SYSTEM RELIABILITY AND RESPONSE TO EMERGENCY CONDITIONS IN THE STATE OF FLORIDA 6 (2007), http://www.psc.state.fl.us/publications/pdf/electricgas/transmissionreport2007.pdf.

region.[110] For reliability purposes in Florida, most of the state operates under the Florida Reliability Coordinating Council (FRCC); most of Texas operates under the Electric Reliability Council of Texas (ERCOT).[111] Both the FRCC and ERCOT are involved in long-term transmission planning for their respective regions.

Unbundled transmission is subject to federal jurisdiction under the Federal Power Act with rate oversight from the Federal Energy Regulatory Commission (FERC).[112] This applies to transmission under the jurisdiction of all the nation's reliability councils including the FRCC but excluding ERCOT. ERCOT's transmission system is not AC interconnected with other states so ERCOT, and not FERC, has jurisdiction over unbundled transmission in its region. The national policy calls for open access to transmission, but there is considerable ongoing debate about how costs should be allocated for those services and who should benefit from transmission investments.[113] Conflicts about cost allocations for use of transmission facilities may hamper investments in them. The ultimate resolution of such conflicts, if there is any, will likely lie outside an individual utility's or a merchant plant's control and therefore raises the risk level for each. However, states can lower investment barriers and reduce perceived investment uncertainty in new generation through new nuclear plant siting at a location pre-designed for

110. These reliability councils are part of the North American Electric Reliability Corporation (NERC), a self-regulatory organization, comprised of eight reliability councils including the Florida Reliability Coordinating Council (FRCC) and ERCOT. For more information about NERC, *see* http://www.nerc.com (last visited May 5, 2008).

111. The FRCC covers peninsular Florida east of the Apalachicola River. Those areas of the state west of the Apalachicola River are within the SERC Reliability Corporation region. ERCOT, an Independent System Operator, covers 75% of Texas and 85% of the Texas load. The remaining portion of population and load is under the jurisdiction of the Southwest Power Pool.

112. The term "unbundling" in this context refers to the functional disaggregation of transmission services from other services provided by an electricity utility. Several rule-making proceedings have laid the foundation for unbundling of transmission services in recent years. Perhaps most significant are the rules promulgated under FERC's Order 888, *Final Rule*, 18 C.F.R. Parts 35 and 385, Docket Nos. RM95-8-000 and RM94-7-001, Apr. 24, 1996. Economist Paul Joskow provides a succinct history of transmission unbundling in his article:

> While Order 888 is very long, the basic principles it embodies are simple: transmission owners must provide access to third parties to use their transmission networks at cost-based maximum prices, make their best efforts to increase transmission capacity in response to requests by third parties willing to pay for the associated costs, and shall behave effectively as if they are not vertically integrated when they use their transmission systems to support wholesale market power transactions, treating third-party transaction schedules on their networks that are supported by firm transmission agreements equivalently to their own use of their transmission network.

Paul Joskow, *Transmission Policy in The United States*, 13 UTIL. POL'Y 95-115, 103 (2005).

113. The Harvard Electricity Policy Group has published numerous papers on the topic of transmission and cost allocation. For a recent paper on the topic of cost allocation, *see* Ross Baldick, Ashley Brown et al., *A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles*, Sept. 2007, *available at* http://www.hks.harvard.edu/hepg/Papers/Rapp_5-07_v4.pdf.

such expansions,[114] streamlined transmission siting processes, public endorsements of the need for future investments in transmission facilities, and congestion reduction efforts.

Both Texas and Florida anticipate extensive transmission improvement projects from 2007-2011: in Texas, needed improvements would cost $3.1 billion[115] if completed, and in Florida, $1.7 billion.[116] Assuming these projects are completed, at least congestion could be alleviated and reliability in power delivery improved. ERCOT's and FRCC's projections are always updated over a multiple-year period because plans inevitably change for both the transmission projects and the generation projects needing additional transmission lines.

C. Projected Demand

Demand growth always constitutes a source of revenue and operating uncertainty for prospective developers because capacity is built based on long-term demand projections. If too much capacity is built, developers run the risk of disallowed capacity costs in a regulated environment or not being able to resell it on favorable terms in a restructured market. In a rate-regulated energy market like Florida's, demand growth projections are typically made in need determination proceedings before a public service commission. What matters for regulated utilities, regardless of the states in which they provide service, is that investments are allowed to be recovered and earn a rate of return as long as they are deemed to be prudent or used and useful. There is no comparable requirement in a restructured environment like in Texas, as potential developers are more interested in markets where they perceive an opportunity for growth in electricity demand. For example, in ERCOT's region (Texas), peak demand grew by 2.5% annually on average from 1990 to 2006.[117] ERCOT projects peak demand growth of 2.1% a year from 2007-2011.[118] Despite

114. Gawlicki, *supra* note 87, at 20.

115. ISO/RTO Council (IRC), IRC SOURCEBOOK 15 (2007), http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_2007%20Sourcebook.pdf.

116. FLA. PUB. SERV. COMM'N, REPORT ON TRANSMISSION SYSTEM RELIABILITY AND RESPONSE TO EMERGENCY CONTINGENCY CONDITIONS IN THE STATE OF FLORIDA 17 (2007), http://www.psc.state.fl.us/publications/pdf/electricgas/transmissionreport2007.pdf.

117. ERCOT, REPORT ON EXISTING AND POTENTIAL ELECTRIC SYSTEM CONSTRAINTS AND NEEDS 8 (2006), http://www.ercot.com/news/presentations/2006/2006_ERCOT_Reports_Transmission_Constraints_and_Needs.pdf. In Florida, by way of comparison, FRCC's region summer peak demand grew by an average of 2.7 % a year. However, winter peak demand declined in Florida by slightly over 1% annually on average during that time period. We computed for Florida the historic percentage changes for both winter and summer peak derived from the FLA. RELIABILITY COORDINATING COUNCIL, 2007 REGIONAL LOAD & RESOURCE PLAN 1 (2007), http://www.psc.state.fl.us/library/filings/07/05795-07/05795-07.pdf.

118. ERCOT, *supra* note 117117, at 8. By way of comparison, the FRCC projects a growth in overall peak demand to be at least 1.75% a year during that time period. This is a lower

the anticipated slower growth rate in peak demand in Texas, demand is still expected to grow, especially in and near metropolitan areas, even though we might want to view demand projections with a certain degree of caution.[119] Capacity still appears to be needed, in part because of reserve margin requirements to which we now turn.

D. Reserve Margins

According to one definition, a reserve margin is "the amount of unused available capability of an electric power system (at peak load for a utility system) as a percentage of total capability."[120] Reserve margins or requirements are established to meet contingencies and provide an acceptable level of unintended service interruptions. Reserve margins, therefore, require suppliers to carry excess generation capacity as a means of ensuring reliable service if there are, for example, widespread generator outages or congestion or outages on key transmission facilities. In a rate-regulated energy market like Florida's, reserve margins often are addressed implicitly in need determination proceedings before a public service commission, thereby mitigating revenue and operating uncertainty about underlying reserve margin assumptions and the potential effects of those projected reserve margins on cash flows during commercial operation.

This is not the case in restructured energy markets: a lower reserve margin portends a greater opportunity to sell wholesale power profitably, in that it signals a higher price on the spot market that reflects energy supply constraints. In a restructured market, prospective merchant developers may perceive an opportunity for nuclear power generation to provide base load generation capacity, particularly if the reserve margin affecting the state or market is declining. One means of risk mitigation in several restructured markets in the United States is the allowance of

projected growth rate for Florida than the average of the preceding 10 years but may correspond to a slowing population growth, greater use of Demand Side Management and energy conservation measures, a slowing growth in Internet connectivity, and higher efficiencies in heating and cooling systems. We computed the projected percentage increase averaging both winter and summer peak derived from the FLA. RELIABILITY COORDINATING COUNCIL, 2007 REGIONAL LOAD & RESOURCE PLAN, *supra* note 117, at 1. Demand during both summer and winter peak is projected to grow but summer more than winter. *See* Fla. Pub. Serv. Comm'n, REVIEW OF 2006 TEN-YEAR SITE PLANS FOR FLORIDA'S ELECTRIC UTILITIES 26-27 (2006), http://www.floridapsc.com/publications/pdf/electricgas/tysp2006.pdf#xml=http://www.psc.state.fl.us/search/pdfhi.aspx?query=DSM&pr=default&prox=page&rorder=500&rprox=500&rdfreq=500&rwfreq=500&rlead=500&rdepth=0&sufs=0&order=r&mode=&opts=&cq=&id=4595d48f18.

119. Long-term energy consumption forecasts, while improving, will always be tricky because of the unpredictability of significant events and forecasters' own biases. *See* Paul Craig et al., *What Can History Teach Us? A Retrospective Examination of Long-Term Energy Forecasts for the United States*, 27 ANN. REV. ENERGY ENVIRON. 83, 113-14 (2002).

120. *See e.g.* TeachMeFinance.com, Definition of Reserve margin (operating), http://www.teachmefinance.com/Scientific_Terms/Reserve_margin_operating.html (last visited May 5, 2008).

capacity payments, whereby electric utilities are required to either have or contract with generators for a prescribed level of reserve capacity above their peak load within a certain time frame.[121] This requirement is not presently imposed by ERCOT (Texas), and therefore is not a risk mitigation measure afforded Texas' merchant developers.

Texas could be facing capacity constraints in coming years. ERCOT's most conservative estimate shows its projected reserve margin falling from 15.2% in 2007 to only 4.9% in 2011. However, if certain thermal units are built, ERCOT projects a reserve margin of almost 24% in 2011.[122] The FRCC projects a reserve margin of 23% (averaging summer and winter) in 2011 if load management and interruptible rates are used.[123] Of course, such short-term projections will not take into account nuclear plant operations because of the long lead time (historically 10.4 years)[124] required for nuclear plants to become commercially operational in the United States. Reserve margins, like projected demand, can be affected by many factors beyond a merchant developer's control, and therefore they pose revenue and operating uncertainties with respect to cash flows following project completion.

E. Public Support

Familiarity with nuclear power generation and the absence of strident

121. It does apply to markets that once operated as tight power pools: PJM, NYISO, and ISO New England. *See* Shmuel S. Oren, *Capacity Payments and Supply Adequacy in Competitive Electricity Markets*, VII SYMPOSIUM OF SPECIALISTS IN ELECTRIC OPERATIONAL AND EXPANSION PLANNING, May 21-26, 2000, at 3, *available at* http://www.pserc.wisc.edu/ecow/get/publicatio/2000public/oren_capacity_payment.pdf.

122. PUB. UTIL. COMM'N OF TEX., *supra* note 19, at 57.

123. FRCC, *supra* note 117, at 28. If load management and interruptible rates are not exercised, the reserve margin declines to an average of 14.5% (average of winter and summer peak loads). Florida's reserve margins have increased since 1995, as electric utilities have replaced inefficient generating units or improved their maintenance of them. In response to the Florida Public Service Commission's concerns over declining reserve margins in the late 1990s, three of the big electric utilities committed to a reserve margin criterion of 20%. This criterion took effect in 2004. *See* FLA. PUB. SERV. COMM'N, A REVIEW OF FLORIDA ELECTRIC UTILITY 2005 TEN-YEAR SITE PLANS 24 (2005), https://www.frcc.com/Public%20Awareness/Shared%20Documents/Reports%20and%20Publications/FPSC/FPSC%20Review%20of%20Electric%20Utility%202005%20Ten%20Year%20Site%20Plans.pdf.

124. The construction of 53 U.S. nuclear power projects that began construction after 1966 and completed construction by 1987 averaged 10.4 years. *See* E. Ray Canterberry, Ben Johnson, and Don Reading, *Cost Savings from Nuclear Regulatory Reform: An Econometric Model*, 62 SOUTHERN ECON. J. 554-56, 563 (1996), 554-566. Assumptions are that new plants will require reduced construction time. The University of Chicago study assumes five to seven years for the construction time for new nuclear power plants using advanced designs. *See* THE ECONOMIC FUTURE OF NUCLEAR POWER S7-S9 (2004), http://www.ne.doe.gov/np2010/reports/NuclIndustryStudy-Summary.pdf; *see also* UNIVERSITY OF CHICAGO STUDY, *supra* note 70, at 9-14. Construction time has decreased for more recently built reactors in Japan. According to the World Nuclear Association, "Japanese reactors which began operating in 1996 and 1997 were built in a little over four years, and 48 to 54 months is typical projection for plants today." *See* World Nuclear Association, *The Economics of Nuclear Power,* Mar. 2008, http://www.world-nuclear.org/info/inf02.html.

opposition may also contribute to a greater comfort level on the part of prospective developers. Both Texas and Florida have nuclear plants in operation (three plants with five units in Florida and two plants with four units in Texas),[125] which means that there is at least local technical expertise for operating such plants, some political acceptance, and a modicum of understanding of the plant siting process. Moreover, in both states, opposition to new coal plants may result in greater interest in the construction of new nuclear power plants to meet base load needs. For example, public opposition in Texas concerning emissions eventually led to TXU's cancellation of eight of eleven coal-fired plants.[126] The Florida Public Service Commission denied a proposal by FPL to construct a 1,960 MW coal-fired plant in Glades County, citing uncertain capital costs and future coal and natural gas prices, in addition to "the currently emerging energy policy decisions at the state and federal level."[127] Florida's governor has voiced concerns about coal-fired generation, stating that he is "not a fan of coal"; nuclear power is an option to be considered, among others.[128] Arguably, public opposition to coal plants does not necessarily translate into public support for nuclear power plants. Moreover, a nuclear power accident within the United States or elsewhere could transform moderate support for nuclear power generation into opposition overnight. Such possibilities raise input cost uncertainties for potential developers because they have no control over events that could lower public support for construction. At the same time, an event stemming from concerns about global warming could conceivably strengthen public support for conservation measures and non-fossil fuel sources for base load power, including nuclear power.

IV. FEDERAL AND STATE POLICIES

The burdens of learning costs on developers of "pioneer" or "first-mover" projects make a compelling case for federal and state incentives to subsidize projects in the early years of a new generation of the technology rather than after the adoption of the advanced technology. Without "pioneers" taking the initial risks, we might expect developers to be less inclined to fund subsequent nuclear power projects. In recent

125. *See* NRC - Texas, *supra* note 98 and NRC - Florida, *supra* note 101.

126. Elizabeth Shogren, *Coal-Fired Plants Scrapped as Part of Utility Deal*, NPR, Feb. 12, 2008, http://www.npr.org/templates/story/story.php?storyId=7615613.

127. Fla. Pub. Serv. Comm'n, *In re* Petition for determination of Need for Glades Power Park Units 1 and 2 Electrical Power Plants in Glades County, by Florida Power & Light Company, *Order Denying Petition for Determination of Need*, Docket No. 070098-EI, July 2, 2007, at 4, *available at* http://www.floridapsc.com/library/filings/07/05350-07/05350-07.pdf.

128. Asjylun Loder, *Plan for $2B Coal Plant Is Quashed: Tampa Electric Changes Course Amid Concerns Over Carbon*, ST. PETERSBURG TIMES, Oct. 5, 2007, at 1A, *available at* http://www.sptimes.com/2007/10/05/news_pf/State/Plan_for_2B_coal_plan.shtml.

years, the federal government has moved toward providing incentives for new nuclear plant construction undertaken either by regulated utilities or merchant plants. These incentives mitigate the risks for "first-movers" that meet certain criteria under EPACT 2005.[129] For example, one such incentive mitigates technical uncertainties related to delays before a plant can begin to generate power by compensating "pioneers" that take the risk. Input cost risk also is mitigated for developers that will learn from the experiences of "pioneers" before deciding to proceed with construction.[130] However, the federal government has not articulated a climate change policy, and the absence of such a policy exacerbates the revenue and operating uncertainty for "first-movers." For its part, state policy can affect uncertainty for developers in a number of ways, including but not limited to creating incentives for the construction of new generation and transmission facilities, providing regulated firms with information about applicable cost recovery treatment well before the plant is constructed, and articulating positions toward issues that may affect revenue and operating uncertainty such as climate change. We summarize a few of the federal and state policies below and discuss how they may mitigate or exacerbate uncertainty for prospective developers.

A. The Energy Policy Act of 2005

One of the objectives of EPACT 2005 is to encourage investment in nuclear power plants.[131] The following is a brief summary of several

129. Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594.

130. *Id.* The U.S. Department of Energy summarizes Section 638 - *Standby Support for Certain Nuclear Plant Delays under Title VI - Nuclear Matters, Subtitle B- General Nuclear Matters*, at http://www.ne.doe.gov/energyPolicyAct2005/neEPACT2a.html.
This section allows the Secretary of Energy to enter into contracts for standby support for delays for up to a total of six reactors of no more than three different reactor designs. Covered delays include the failure of the Nuclear Regulatory Commission (NRC) to comply with schedules for review and approval of inspections or the conduct of hearings, in addition to litigation that delays full-power operation. The Secretary of Energy would pay 100 percent of the covered costs for the first two reactors that have received a combined license and for which construction has begun. *Id.*

131. President George W. Bush explained the intent of EPACT 2005 as it applied to nuclear power-related incentives as follows:

> Nuclear power is another of America's most important sources of electricity. Of all our nation's energy sources, only nuclear power plants can generate massive amounts of electricity without emitting an ounce of air pollution or greenhouse gases. And thanks to the advances in science and technology, nuclear plants are far safer than ever before. Yet America has not ordered a nuclear plant since the 1970s. To coordinate the ordering of new plants, the bill I sign today continues the Nuclear Power 2010 Partnership between government and industry. It also offers a new form of federal risk insurance for the first six builders of new nuclear power plants. With the practical steps in this bill, America is moving closer to a vital national goal. We will start building nuclear power plants again by the end of this decade.

See George W. Bush, President of the United States of America, President Signs Energy Policy Act (Aug. 8, 2005), *available at*
http://www.whitehouse.gov/news/releases/2005/08/print/20050808-6.html.

provisions of EPACT 2005 that further that objective. Section 1306 of the Act authorizes a production tax credit of 1.8 cents per kilowatt-hour to any advanced nuclear facility[132] that begins construction before January 1, 2014, and is commercially operable by January 1, 2021. These tax credits are limited to a maximum of $125 million a year and apply to the first eight years of the plant's operation. These tax credits also only apply nationwide to a maximum of six gigawatts of new nuclear power capacity. Production tax credits primarily address revenue and operating uncertainty by providing a more favorable and predictable cash flow during commercial operation as some sort of buffer against unpredictable price fluctuations, such as those associated with fuel prices and energy demand during the multiple decades of a nuclear plant's operation to help recover costs. Production tax credits also attempt to mitigate risk associated with technical uncertainty to provide incentives for potential developers to be "pioneers" to build the first projects, albeit in an indirect manner: the presence of the tax credit makes it worthwhile for a developer to start a project because the value of the project increases, thus making it more cost effective to start the project and then abandon it if the project becomes too costly.[133] Moreover, the production tax credit also may indirectly mitigate risk associated with input cost uncertainty for those developers that wait and allow "first-movers" to reveal more information about the regulatory environment for developing nuclear projects.

Section 1703 of EPACT 2005 authorizes the U.S. Secretary of Energy to guarantee loans of up to eighty percent of a project's construction costs. Advanced nuclear energy facilities are among the projects eligible for such guarantees.[134] The loan guarantee should reduce the financial risk associated with input cost uncertainty by reducing the weighted average cost of capital necessary to finance the project, and thus encourage potential developers that otherwise may have preferred to delay investments and gain more information from the experiences of others before developing new nuclear plants. In addition, Subtitle A of Title 6 includes provisions to update the Price-Anderson Act Amendment to the Atomic Energy Act of 1954. These new provisions ensure liability coverage for all nuclear plants in the event of an accident.[135] Small modular reactors may be combined and considered one unit for liability purposes.[136] By reducing a developer's exposure to

132. Energy Policy Act of 2005, Pub. L. 109-59 § 1306(d)(2) (2005) (defining "advanced nuclear facility" as "any nuclear facility the reactor design for which is approved after December 31, 1993, by the Nuclear Regulatory Commission").

133. *See generally supra* Part I; Pindyck, *supra* note 20.

134. Energy Policy Act of 2005, Pub. L. 109-58 § 1703(b)(4) (2005).

135. Energy Policy Act of 2005, Pub. L. 109-58 §§ 601-606 (2005).

136. Energy Policy Act of 2005, Pub. L. 109-58 § 608 (2005).

liability, this incentive should reduce revenue and operating uncertainty. Absent such liability coverage, a catastrophic accident would more likely result in bankruptcy because the plant's revenue stream would be disrupted, and therefore would be unlikely to pay for extensive damages to people and property.

Section 1310 of EPACT 2005 modifies the tax treatment of nuclear decommissioning funds to allow non-utilities to make deductible contributions to a qualified nuclear decommissioning fund. Prior to enactment of EPACT 2005, this preferred tax treatment was authorized only for rate-regulated utilities. Moreover, Section 1310 repeals a limitation on the amount that could be accumulated in the decommissioning fund. Now companies may accumulate an amount sufficient to cover all of the plant's estimated decommissioning costs. Like the liability guarantee, the modified tax treatment for decommissioning contributions would remove for merchant plants the revenue and operating uncertainty created by the unidentifiable magnitude of the decommissioning costs at the end of commercial operation which is passed along to ratepayers.[137]

Finally, Section 625 of EPACT 2005 removes the NRC's authority to conduct antitrust reviews of the applications for new nuclear reactor licenses.[138] This provision also appears to remove a hurdle for an application to be challenged, reducing both the input cost uncertainty associated with applications and the possibility of delay that would raise the costs of the project.

B. Implementation of EPACT 2005

Although these federal incentives undoubtedly have articulated a policy interest in expediting nuclear plant construction by mitigating some of the risk to developers and ratepayers and shifting it to taxpayers, questions remain concerning implementation.[139] With respect to the implementation of the production tax credit, the EIA points out that the per-kilowatt tax credit is not indexed to the rate of inflation. Thus, the

137. *See* Energy Policy Act of 2005, Pub. L. 109-58 § 1310(a), (f) (2005) (also repeals the cost of service requirement governing deductible contributions to a decommissioning fund and (f) authorizes contributions to be made for decommissioning costs prior to 1984).

138. The NRC recommended this change, contending that such a review duplicates the work of other federal agencies such as the Federal Energy Regulatory Commission and the U.S. Department of Justice. *See Statement Submitted by the United States Nuclear Regulatory Commission: Hearing on the Energy Policy Act of 2005 Before the Subcomm. on Energy and Air Quality of the H. Comm. on Energy and Commerce,* 109th Cong. 4 (2005) (statement of Luis A. Reyes, Executive Director of Operations), *available at* http://www.nrc.gov/reading-rm/doc-collections/congress-docs/congress-testimony/2005/ml050410030.pdf.

139. Lacy, *supra* note 16, at 5. ("The new plant licensing process is a good but untried concept and the courts will likely be involved in what the final version looks like.") *See Statement Submitted by the United States Nuclear Regulatory Commission*, *supra* note 138, at 5.

real value of the tax credit could be reduced by approximately twenty-five to thirty percent when the first nuclear plant eligible for the production tax credit comes on line in about 2015,[140] thereby reducing its effectiveness in addressing revenue and operating uncertainty, technical uncertainty, and input cost uncertainty. Moreover, with respect to the loan guarantees authorized under EPACT 2005, the U.S. Department of Energy will not guarantee more than 80% of total debt. Therefore, if the project's financing is eighty percent debt and twenty percent equity, the department will guarantee no more than sixty-four percent of the project's total cost.[141] However, as EIA observed: "Such loan guarantees could affect the economics of nuclear power, because they could reduce the effective interest rates on the debt and allow utilities to use much more debt financing."[142] Loan guarantees, by lowering the overall project cost, provide greater input cost certainty. Production tax credits, by increasing cash flow, provide developers with more revenue and operating certainty.

C. Streamlined Licensure

The NRC licenses all commercially owned nuclear power plants producing electricity in the United States. Once a plant obtains a license, that license may be amended, renewed, transferred, or modified. The NRC is responsible for monitoring and evaluating the commercial performance of licensed plants and for regulating the storage of spent fuel. All applications for licensure of new nuclear plants are reviewed by the NRC for safety, environmental impact, and (previously) for antitrust implications. The nuclear plants that are currently operating were required to furnish information on these issues as part of a two-step licensing process that issued a construction permit and an operating license. In 1989, the NRC instituted a streamlined approval process that combines construction and operating licenses based on a review of the same information required of each previously. The intent was to "improve regulatory efficiency and add greater predictability to the process."[143] Other measures adopted in regulations to expedite approval

140. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK, *supra* note 10, at 21. The U.S. Senate included a provision in an energy bill which would have expanded the loan guarantee program, but it was opposed by the House and the Bush Administration. *See* Edmund L. Andrews & Matthew L. Wald, *Energy Bill Aids Expansion of Atomic Power*, N.Y. TIMES, July 31, 2007, at 1, *available at* http://www.nytimes.com/2007/07/31/washington/31nuclear.html.

141. *Id.*

142. *Id.*; *see also* Consolidated Appropriations Act of 2008, H.R. 2764, DIVISION C—ENERGY AND WATER DEVELOPMENT AND RELATED AGENCIES APPROPRIATIONS ACT, 2008, which authorized $18.5 billion for the Innovation Technology Loan Guarantee Program. However, a fee imposed by the U.S. Department of Energy for the evaluation of early reactor projects could present a stumbling block for prospective developers. *See* Gawlicki, *supra* note 87, at 20.

143. U.S. NUCLEAR REGULATORY COMM'N, BACKGROUNDER ON NUCLEAR POWER

include early site permits and the development of certified standard plant designs which can be used as pre-approved designs.[144] These approaches to streamlining licensure could reduce input cost uncertainty, but no new nuclear plant has been approved using them. Therefore, no one knows whether companies actually will save time and money. And there is always the risk that an insufficient number of plants with any one design will be constructed to achieve critical economies of scale and increase the learning curve derived from previous design and construction experiences.[145]

Already, certification of a pre-approved design has raised some challenges for the NRC. For example, NRG Energy submitted an application for a GE-designed reactor that was certified in 1996. The company is seeking permission from the NRC to incorporate technological changes made in Japan during the past decade to improve that model's operations. However, this approach also could present some risk for applicant utilities and merchant developers because modifications they propose can be challenged, and such challenges might result in lengthy delays.[146] On the one hand, delays allow time for acquiring better information about the disposition of an evolving policy and thus reduce input cost uncertainty for those opting to wait. On the other hand, corporate funds are tied up for a longer time in the construction phase of the project. Furthermore, cash flows from plant operation are then delayed, thereby reducing the expected net present value of associated operating cash flows. The streamlined licensing process also imposes input cost uncertainty for developers as compliance costs are difficult to forecast, particularly if compliance requirements, such as measures to improve a plant's safety, change during the construction period.

D. Incentives for New Generation

There is considerable uncertainty concerning the actual time horizon to construct a new nuclear power plant and bring it on line and the factors that could affect project completion. Cost overruns were certainly endemic to the nuclear power industry in the 1970s and 1980s for a host

PLANT LICENSING PROCESS (2005), http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/licensing-process-bg.pdf.

144. *Id.* The alternative licensing processes have yet to be used. They are authorized under 10 C.F.R. Part 52—Licenses, Certifications, and Approvals for Nuclear Power Plants (2008). Subpart A applies to early site permits, Subpart B to standard design certifications, and Subpart C to combined licenses. *Id.*

145. David Schlissel, The Risks of Building New Nuclear Power Plants, Presentation to Utah State Legislature Public Utilities and Technology Committee 31 (Sept. 19, 2007), *available at* http://www.nirs.org/nukerelapse/neconomics/utahstatelegislative091907.ppt.

146. Rebecca Smith, *New Hurdle for Nuclear Plants*, WALL ST. J., Oct. 15, 2007; *see also* Gawlicki, *supra* note 87, at 20. On the other hand, NRG Energy's justification for using this technology is that it has a proven track record in Japan.

of reasons that are difficult to disentangle, including slowing electricity consumption, high interest and inflation rates, growing public opposition, poor project management, and regulatory changes made in response to poor plant operating performance.[147] The Nine Mile Point 2 nuclear power plant in upstate New York is perhaps one of the more extreme examples of a costly plant with a cost of $10,679 per kilowatt. Its original estimated cost was $500 million in 1973, but costs soared to $6.3 billion (nominal dollars) in 1987 upon project completion.[148]

Prospective developers tend to look favorably at any policies that will reduce technical, input cost, and revenue and operating uncertainties. The four merchant developers that are planning to construct nuclear plants in Texas are not required to demonstrate to a regulatory body that those plants are needed.[149] Expected wholesale market prices therefore signal the need for additional capacity from merchant developers and provide some assurance that they have an opportunity to be profitable. For example, a rule adopted by the Public Utility Commission of Texas allows wholesale prices to rise in response to a scarcity in resources and phases in higher offer caps in the wholesale market over a three-year period.[150] This rule is particularly important to merchant plants serving Texas because ERCOT has an energy-only market design: generators are only compensated for the energy they sell. There is no payment made for capacity—that is, for building plants and keeping them in operation.[151] So in contemplating new capacity construction, prospective developers need the assurance that offers from generators, and the resulting market prices, will give them an opportunity to recover their costs and thus reduce revenue and operating uncertainty. However, the downside of the ERCOT approach is that it may meet with political resistance in times of higher wholesale market prices. An alternative approach of some wholesale markets (not ERCOT) is the use of capacity payments that afford merchant plants some predictability in their revenue streams.[152]

In 2006, the Florida Legislature created incentives by enacting legislation that, among other provisions, streamlined generation siting to accomplish the following: combine the determinations of completeness and sufficiency of a utility's application for a certification for a new generation plant to ensure that reviewing agencies have the necessary information to prepare required reports; eliminate mandatory land use

147. The Keystone Center, *supra* note 23, at 31.

148. James Sterngold, *Niagra Is Writing Off $755 Million*, N.Y. TIMES, July 24, 1987. Niagara Mohawk Power in upstate New York operated the plant before selling most of it to Constellation Energy Group. The plant began commercial operations in 1988.

149. However, they are required to obtain applicable environmental permits.

150. TEX. UTIL. CODE ANN. § 25.505 (Vernon 2008).

151. PUB. UTIL. COMM'N OF TEX., *supra* note 19, at 12.

152. *See* explanation for capacity payments in Part III, at 25.

and certification hearings under certain circumstances; and change deadlines in many cases by expediting the reviews needed for decision-making.[153] This streamlined generation siting process applies to all companies seeking new generation in Florida, including nuclear power plants.[154] The same legislation also specifically addresses the construction of nuclear plants by changing the criteria the Florida Public Service Commission must consider in making its need determination.[155] Finally, the legislation exempts the utility applicant from the Commission's requirement that competitive bids for power supply be secured prior to submission of an application under the Siting Act or the Commission's decision on determination of need.[156] The intended effect of these measures appears to provide incentives for construction of nuclear plants. We might expect the streamlined process for siting coupled with the exemption from the competitive bid requirement to reduce the time period for the Commission to respond to the utility's application for the new plant, thereby reducing input cost uncertainty associated with the regulatory siting and permitting process. Because this legislation was enacted fairly recently (in 2006), we do not know yet how these policy changes will actually affect a nuclear plant's construction timeline and thus its associated costs.

E. Incentives for Transmission Siting

With the exception of power generated from rooftop photovoltaic systems and distributed generation systems, all power must be transmitted from the point of generation. Therefore, the transmission system must be an integral part of considerations for the location of new generation. Integrated utilities that can build their own transmission lines to support proposed new generating units can control some of the conditions involved in ensuring adequate and reliable transmission facilities—thus reducing some revenue and operating uncertainty. Merchant developers do not have such capabilities.[157]

153. 2006 Fla. Laws 230, codified as FLA. STAT. § 403.501-519 (2007).

154. FLA. STAT. § 403.503 (2007). An "electrical power plant" is defined as "for the purpose of certification, any steam or solar electrical generating facility using any process or fuel, including nuclear materials, except that this term does not include any steam or solar electrical generating facility of less than 75 megawatts in capacity unless the applicant for such a facility elects to apply for certification under this act." § 403.503(13)

155. 2006 Fla. Laws 230, § 43, codified AS FLA. STAT. §§ 403.519(3) (2007).

156. § 403.519(4)(c).

157. To complicate matters in many states (not Texas and Florida to date), transmission project oversight is shared by state utility commissions and FERC. Transmission project determinations have historically been the jurisdictional domain of state regulators. However, Section 1221(a) of EPACT 2005 granted FERC "backstop authority" for determining interstate transmission facilities in congested areas determined by the U.S. Department of Energy to be "national interest electric transmission corridors." We note that Section 1221(a) of EPACT 2005 added new Section 216 to the Federal Power Act (16 U.S.C. § 824p). New Section 216 requires the Secretary of Energy to conduct a nationwide study of electric transmission within one year of

Transmission siting faces several obstacles throughout the nation including complicated state regulatory processes frequently involving input from competing interest groups, various local government agencies, and the courts; public resistance to transmission lines (the "not in my backyard" response); increased competition for available land on which to construct transmission lines leading to rising costs when property valuations increase; and problems with gaining approval for a transmission project that crosses state lines.[158] In some cases, utilities and merchant developers may reduce cost uncertainties, some of which fall under Pindyck's input cost category, such as public opposition and governmental policy changes in the midst of project development, by locating nuclear plants in close proximity to existing plants and transmission facilities.[159] Revenue and operating uncertainty may be reduced through the use of existing transmission capacity or rights of way which can be upgraded to handle greater flows of power. State legislation streamlining transmission siting processes, like those enacted in Florida in 2006,[160] also may contribute to greater predictability and reduced input cost uncertainty, especially if transmission is to be constructed as a result of, and in parallel with, the development of the nuclear project.

F. Climate Change Policy

To date there is no climate change policy at the federal level, only policies that are being contemplated and developed by individual states either alone or in concert with other states.[161] Yet in spite of the lack of a

the date of enactment and every three years thereafter. The first report was completed in August 2006 and is available at U.S. DEP'T OF ENERGY, NATIONAL ELECTRONIC TRANSMISSION CONGESTION STUDY (2006), http://nietc.anl.gov/documents/docs/Congestion_Study_2006-9MB.pdf. In addition, the U.S. Department of Energy explained that the national corridor designation was not a siting decision. According to the Department, "FPA Section 216(a) does not shift to the Department the role of designing routes for transmission facilities, and a National Corridor designation does not dictate or endorse the route of any transmission project. If a transmission project is proposed in a National Corridor, it will be the State or local siting authorities, and potentially FERC if certain conditions are met, that will determine the specific route of that project." *See* U.S. Department of Energy, National Electric Transmission Congestion Report, 72 Fed. Reg. 56,995 (Oct. 5, 2007). The jurisdictional issue raises questions about future jurisdictional responsibility for reliability. One law review article went so far as to advocate that "Congress should have granted FERC exclusive jurisdiction over transmission siting, making the FPA mirror the Natural Gas Act (NGA)." *See* Joshua P. Fershee, *Misguided Energy: Why Recent Legislative, Regulatory, and Market Initiatives are Insufficient to Improve the U.S. Energy Infrastructure,* 44 HARV. J. ON LEGIS. 327, 360-61 (2007).

158. FLA. PUB. SERV. COMM'N, *supra* note 109 at 23.

159. This point is also made by Gawlicki, *supra* note 87, at 20.

160. 2006 Fla. Laws 230, codified as FLA. STAT. §§ 403.52-539 (2007).

161. Florida's Governor Crist issued Exec. Order Number 07-127, which established targets for greenhouse gas emission reduction for 2017, 2025, and 2050. *See* Office of the Governor*, Establishing Immediate Actions to Reduce Greenhouse Gas Emissions within Florida,* July 13, 2007, at http://www.flgov.com/pdfs/orders/07-127-emissions.pdf. Other states have also initiated greenhouse reduction efforts. For example, in December 2005, seven states signed a memorandum of understanding to participate in the Regional Greenhouse Gas Initiative: Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont. In 2006,

policy at the federal level, there is a growing belief that federal climate change policy is inevitable. However, the form and stringency of the policy remains unknown.[162] In Texas, there is no policy, but in Florida Governor Charlie Crist has recently signed an Executive Order that would mandate cuts in carbon dioxide emissions from electric utilities such that by 2015 utilities would achieve year 2000 emissions levels, by 2025 utilities would achieve 1990 levels, and by 2050 an 80% reduction from 1990 levels, though the form of the policy remains unknown as yet.[163] While the form of the policy in Florida has yet to be determined, the mandated reductions provide a clear indicator of the need for, and cost-effectiveness of, non-carbon emitting technologies such as nuclear power to achieve the mandated reductions. The articulation of a policy, even if it is only the reduction of emissions rather than the price of carbon, reduces revenue and operating uncertainty for nuclear power since there is cost advantage over coal and natural gas to being a non-carbon emitting technology. On the other hand, the lack of policy direction at the federal level leaves a large part of the revenue and operating uncertainty unresolved and may result in potential developers exercising their option to wait for clearer policy direction.

V. CONCLUSION

In the next few years, our national debate on nuclear energy will require us to come to better terms with all the uncertainties surrounding the construction and operation of new nuclear power plants. A more informed understanding of differences nuclear plant developers face in restructured energy markets, like Texas, and rate-regulated markets, like Florida, might be the first step toward evaluating the risks associated with construction and commercial operation, although in both markets, developers will gauge a number of factors: a state's overall energy portfolio, its commitment to transmission facility improvements, projected electricity demand, capacity constraints and reserve margins,

these states issued a model set of rules which were outlined in the memorandum of understanding. *See* Regional Greenhouse Gas Initiative, Multi-State RGGI Agreement, http://www.rggi.org/agreement.htm (last visited May 5, 2008). California's legislation (AB 32) to reduce carbon emissions was enacted in California in September 2006. This legislation is aimed at statewide carbon emission reductions to 1990 levels by 2020 with reductions to continue through 2050. *See* Office of the Governor, *Governor Schwarzenegger Signs Landmark Legislation to Reduce Greenhouse Gas Emissions*, Sept. 27, 2006, http://gov.ca.gov/index.php?/press-release/4111.

162. One such example is the Business Environmental Leadership Council established by the Pew Center which consists of 43 U.S.-based companies with 3.8 million employees. This council supports strong action to reduce greenhouse gas emissions. *See* Eileen Claussen, President, Pew Center on Global Climate Change, Can Technology Transform the Climate Debate?, (May 16, 2007), at http://www.pewclimate.org/press_room/speech_transcripts/clauseen516.cfm.

163. Exec. Order Number 07-127 § 1, *supra* note 161.

and the nature of public support. Developers in both regulated and market environments retain the option of delay before starting a nuclear power project as a means of mitigating risk associated with input cost and revenue and operating uncertainties, and may elect to start a project while retaining the option to abandon the project should it be seen as too expensive or unprofitable. The option to delay or abandon a project is especially important for developers operating in a market environment where the "market review" is always in hindsight, and the investors bear all the risk and reward of exercising the option.[164] A rate-regulated utility developer faces an additional constraint with regard to the options of delay or abandonment that merchant developers do not encounter: the "obligation to serve" its load. Consequently, the exercise of the delay or abandonment options would require the regulated developer to turn to another technology/fuel option to meet reserve margins and serve load during an interim period. In this case, consumers are likely to bear the risks and reward of the exercise of the option.

The goal of federal and state policies is to mitigate risk associated with uncertainties through means other than project delay or abandonment so that projects can go forward. Federal and state policies to reduce uncertainty facing prospective developers have been largely directed toward reducing revenue and operating uncertainty, and many of the issues involved in the calculus to proceed with a nuclear plant affect cost recovery and revenue streams during a plant's commercial operation: fuel costs, access to reliable transmission facilities, future demand, and reserve margins. The fact that much of the federal and state policies attempt to mitigate this type of uncertainty reflects the magnitude of revenue and operating uncertainty for prospective developers. Policies that can be implemented to mitigate revenue and operating uncertainty and thereby reduce the risk to developers of inadequate cost recovery, such as Florida's legislation governing preconstruction cost recovery treatment and Texas' rule authorizing higher offer caps to respond to conditions of fuel scarcity in the wholesale market, can augment the measures authorized under EPACT 2005 to that end. While the state policies often shift some risk from developers to consumers, many of the federal policies under EPACT 2005, such as liability limitations, the production tax credit, and loan guarantees, spread risks beyond the developer or consumers directly affected by the project to the body of taxpayers nationwide. However, before developers will proceed to the construction phase, mitigation strategies addressing technical and input cost uncertainty are critical. Federal and state policies that streamline or facilitate licensing and generation and transmission siting processes may

164. Baumol & Sidak, *supra* note 52, at 391.

reduce input cost uncertainty. Technical uncertainty may be mitigated indirectly through production tax credits authorized under EPACT 2005. Pindyck's model assumed that technical and input cost uncertainty facing prospective (vertically-integrated and rate-regulated) developers was more pressing to prospective developers than revenue and operating uncertainty; his model did not formally account for the latter.

The results of the MIT study suggest that any efforts to offset most forms of technical or input cost uncertainty that ultimately result in reduced capital costs of shorter construction times are helpful but not sufficient to make nuclear power cost competitive with coal and natural gas technologies.[165] The targeted policy of loan guarantees in EPACT 2005 which should reduce the cost of capital may be the most effective policy for mitigating input cost uncertainty to make nuclear generation more competitive with other generating sources.

Our analysis suggests that revenue and operating uncertainty is actually more dominant and pressing than the other types of uncertainty discussed above, and our analysis shows that a number of strategies have been deployed to mitigate it. For example, the federal production tax credit authorized under EPACT 2005 may help reduce this type of uncertainty. Nonetheless, according to the MIT study, in the absence of reductions in overall capital costs or construction times, the tax credit alone would be insufficient to make nuclear competitive with coal or gas.[166]

Finally, a looming uncertainty is the treatment of carbon emissions at the national level. As the MIT study shows, nuclear generation becomes more attractive relative to other generation sources if a national carbon reduction policy is adopted, particularly in conjunction with reduced capital costs and construction times.[167] Even in the absence of reduced capital costs or reduced construction times for nuclear power, placing a sufficiently high price on carbon emissions should make nuclear power the least-cost option for new base load generating capacity.[168] However, individual federal and state incentives and strategies addressed above may matter less than their cumulative effect on reducing perceived

165. MIT STUDY, *supra* note 69, at 42 tbl.5.1.

166. In the MIT STUDY, the levelized cost of nuclear over a 25-year period is 7.0 cents/kWh, while the levelized cost of coal is 4.4 cents/kWh, and the levelized cost of gas combined cycle is 5.3 cents/kWh in the high gas cost case. Given the production tax credit is 1.8 cents/kWh and is not indexed to account for inflation, it is declining in real terms and would not be enough to offset the cost differences between the technologies. *Id.*

167. *Id.* at 42 ("With carbon taxes in the $100/tC to $200/tC range, nuclear power would be an economical base load option compared to coal under the base case assumptions, but would still be more costly than gas except in the high gas price case. However, nuclear would be significantly less costly than all of the alternatives with carbon prices at this level, if all of the cost reduction specifications discussed earlier could be achieved.").

168. *Id.* at 42 tbl.5.1.

investment risk: all three types of uncertainty—technical, input cost, and revenue and operating uncertainty—need to be mitigated for a nuclear plant to be constructed and operated in the current market.