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Reports

Markets for Power in the United States: An Interim Assessment

*Paul L. Joskow**

The transition to competitive wholesale and retail markets for electricity in the U.S. has been a difficult and contentious process. This paper examines the progress that has been made in the evolution of wholesale and retail electricity market institutions. Various indicia of the performance of these market institutions are presented and discussed. Significant progress has been made on the wholesale competition front but major challenges must still be confronted. The framework for supporting retail competition has been less successful, especially for small customers. Empirical evidence suggests that well-designed competitive market reforms have led to performance improvements in a number of dimensions and benefited customers through lower retail prices.

1. INTRODUCTION

Despite longstanding academic interest (Joskow and Schmalensee (1983)) and some previous experience in other countries, comprehensive electricity sector restructuring and competition initiatives only began to be taken seriously by U.S. policymakers in the mid-1990s.[1] The first U.S. retail competition and restructuring programs began in Massachusetts, Rhode Island and California in early 1998 and

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* Professor of Economics, Massachusetts Institute of Technology, 50 Memorial Drive, E52-271D, Cambridge, MA 02142, USA. E-mail address: pjoskow@mit.edu.

1. Of course, wholesale power markets in which proximate vertically integrated utilities traded power on a daily and hourly basis subject to very limited regulation, have existed in the U.S. for many years. In addition, during the 1980s the Public Utility Regulatory Policy Act (PURPA) of 1978 stimulated the development of a non-utility power sector selling electricity produced primarily from cogeneration facilities and renewable energy facilities to local utilities under long-term contracts (Joskow, 1989). The Energy Policy Act of 1992 also removed important barriers to the broader development of unregulated non-utility generating facilities and expanded the Federal Energy Regulatory Commission's (FERC) authority to order utilities to provide transmission service to support wholesale power transactions. However, these developments largely reflected modest expansions of competition at the wholesale level built upon a basic model of regulated vertically integrated franchised monopolies.

spread to about a dozen additional states by the end of 2000. By that time several additional states had announced plans to introduce similar programs in the near future and a competitive market model for the electricity industry seemed to be sweeping the United States. The primary political selling point for competition in those states that were early adopters was that it would benefit consumers by leading to lower costs and lower prices in both the short run and the long run. The ideological commitment to competition as an alternative to regulated monopoly that characterized the Thatcher government's electricity sector privatization, restructuring and competition program in the United Kingdom (UK) was not a powerful force driving these reforms in the U.S. Indeed, the vast majority of the states that have implemented comprehensive wholesale and retail electricity competition initiatives cast their electoral votes for Al Gore in 2000 and John Kerry in 2004 and neither President Bush nor many of the states that gave him his greatest support have been strong supporters of comprehensive electricity sector restructuring and competitive market initiatives.[2]

The Federal Energy Regulatory Commission (FERC) supported the development of competitive wholesale markets during both the Clinton and Bush administrations. In 1996 FERC adopted rules specifying new requirements for transmission-owning utilities to make available open access transmission service tariffs (Order 888) and provide information about the availability and price of transmission service on their networks (Order 889). In late 1999 FERC embraced a more aggressive restructuring and wholesale market institutional change agenda in its Regional Transmission Organization (RTO) rule (Order 2000). It used various carrots and sticks to induce utilities and state regulators to adopt an aggressive restructuring and competition agenda.

However, the California electricity crisis of 2000-2001 (Joskow (2001)), concerns about market power problems there and elsewhere, phantom trading and fraudulent price reporting and accounting revelations, Enron's bankruptcy, and the financial collapse of many merchant generating and trading companies subsequently took the glow off of "deregulation." Rising wholesale market prices, resulting from rising natural gas and coal prices, closed or reversed the gap between the generation cost component of bundled regulated retail prices and the prices for equivalent generation services purchased in competitive wholesale power markets. This further reduced the interest of consumers and politicians in market-based prices, especially in those states with relatively low regulated prices. The slow pace at which retail customers switched to competitive suppliers in those states that adopted retail competition programs was disappointing and in turn led to a declining number of competitive retail supply options for residential and small commercial customers in many of those states.

Since the year 2000 no additional states have announced plans to introduce competitive reforms and several states that had planned to implement

2. When President Bush was Governor Bush he did support a comprehensive restructuring and competition program in Texas.

reforms have delayed, cancelled or significantly scaled back their electricity competition programs. Moreover, FERC's efforts to promote a competitive wholesale restructuring and competition model with a small number of RTOs covering large regions of the country and meeting stringent criteria for market design, geographic scope and independence confronted increasing political opposition after 2000. FERC found itself at war with many states in the Southeast and the West as they resisted its efforts to expand wholesale market and transmission institutions that it had identified as being necessary to support efficient competitive wholesale markets in all regions of the country. FERC's proposed Standard Market Design (SMD) rule issued in 2002 created enormous controversy and was withdrawn entirely in July 2005. The pressure from FERC to implement fully and effectively the creation of RTOs pursuant to Order 2000 appears to have receded as well. Re-integration of generation with transmission and distribution has begun to occur in a few states. Even the Cato Institute has lost patience with competitive reforms in electricity and appears to see merit in returning to the good old days of regulated vertically integrated utilities (Van Doren and Taylor (2004)). At the same time, most of the states in the Northeast, a few in the Midwest, and Texas, appear to be committed to moving forward with the development of competitive wholesale and retail markets and to making them work well, though the strength of the policy commitment to competitive electricity markets may have declined in these states as well.

After nearly 25 years of federal and state restructuring, regulatory reform and deregulation initiatives affecting almost every U.S. industry that had been subject to price and entry regulation prior to 1980, the deregulation policy ship appears to have run aground as it tries to lead the U.S. electric power industry along a path to competition. What is the problem? Are things as bad as opponents of competition suggest? Or does it depend on whether one looks at the glass being half empty or half full? What needs to be done to fix the problems that are really there to make a competitive model more attractive?

One of the challenges associated with providing objective answers to these questions for the U.S. is the lack of any comprehensive assessments of the effects of these reforms on costs, prices, innovation, and consumer welfare of the type that has been done, for example, for the UK (e.g. Newbery and Pollitt (1997), Domah and Pollitt (2001)). This kind of counterfactual analysis is difficult to do well under any circumstances. It is especially challenging when the data available to compare performance under regulated and competitive regimes is extremely limited, as is the case in the U.S. In this paper, I offer an array of "fragments of evidence" to illuminate what we know and what we don't know about the effects of competitive reforms on various performance indicia for the electricity industry in the United States to date. I examine the evolution and effects of both wholesale and retail competition reforms. I view this as an interim assessment because the restructuring and competition program for the electricity sector in the U.S. is clearly incomplete and a work in progress.

2. EVOLUTION OF NEW WHOLESALE MARKET INSTITUTIONS

The foundation of any well-functioning competitive electricity market system (with or without retail competition for all end-use customers) is a well-functioning wholesale market and supporting transmission network operating and investment institutions. Wholesale electricity markets do not design themselves but must be designed as a central component of any successful electricity restructuring and competition program. The U.S. electricity sector's legacy industry structure built upon a large number of regulated vertically integrated monopolies and nearly 150 network control areas was not conducive to creating well functioning competitive wholesale and retail electricity markets (Joskow and Schmalensee (1983), Joskow (2000, 2005a)). However, unlike England and Wales, Norway, Sweden, Spain, Australia, New Zealand, Argentina and other countries, the U.S. did not proceed with its wholesale and retail competition initiatives with a clear coherent blueprint for vertical and horizontal restructuring, wholesale market design, transmission institutions, or retail competition. There has been no federal legislation endorsing a comprehensive national electricity restructuring and competition policy. Horizontal and vertical restructuring has been much more limited than would have been ideal to support a smooth transition to competitive wholesale and retail markets. Rather than relying on a clear and coherent national reform policy with supporting federal legislation, as was the case for the earlier reforms applied to airlines, trucking, railroads, and telecommunications, electricity sector reforms have depended on regulatory initiatives taken by FERC under statutes that are 60 years old and by diverse and often inconsistent policies adopted by individual states.

2.1 FERC Takes the Lead

FERC has undertaken a number of initiatives to support the creation of competitive wholesale markets that are consistent with the diverse restructuring and competition policies that have been adopted by different states and associated political constraints on FERC's authority. Orders 888 and 889 issued in 1996 (and subsequently amended a number of times) required transmission owners to provide access to their networks at cost-based prices, to end discriminatory practices against unaffiliated generators and marketers, to expand their transmission networks if they did not have the capacity to accommodate requests for transmission service, and to provide non-discriminatory access to information required by third parties to make effective use of their networks.

FERC Order 2000 issued in December 1999 contained a new set of regulations designed to facilitate the "voluntary" creation of large Regional Transmission Organizations (RTO) to resolve what FERC perceived as problems created by the balkanized control of U.S. transmission networks and alleged discriminatory practices affecting independent generators and energy traders seeking to use the transmission networks of vertically integrated firms under

Order 888 rules.[3] Order 2000 also articulates several important goals for wholesale market institutions and represents a very significant step forward in the framework supporting the development of competitive wholesale electricity markets. These include (a) the creation of independent transmission system operators who will operate the transmission network reliably and economically without being influenced by the financial interests of generators, wholesale and retail markets of power; (b) the creation of large regional transmission networks with common transmission access and pricing rules and common wholesale market institutions to mitigate inefficiencies associated with the balkanized ownership and operation of transmission networks in the U.S.; (c) the creation of a set basic wholesale market institutions to support buying and selling power economically and for allocating scarce transmission capacity efficiently.

In mid-2002 FERC commenced a new rulemaking proceeding to consider a proposal for a "Standard Market Design" or "SMD" that would apply to all transmission-owning utilities over which FERC had jurisdiction. The proposed SMD rule enumerated a much more detailed set of wholesale market design requirements : (a) an Independent Transmission Provider (ITP) would be required to assume operating responsibility of all transmission systems, no matter how small; (b) a locational marginal pricing (LMP) based organized day-ahead and real time wholesale market design and congestion management system similar to those that were already in place in PJM and New York; (c) resource adequacy requirements that would obligate all load serving entities (LSEs) to make forward commitments for generating capacity and/or demand response to meet their forecast peak demand plus a reserve margin to be determined through a regional stakeholder process; (d) a regional transmission planning and expansion process would be implemented to identify transmission investment needs for interconnection, to meet reliability requirements, and that are economically justified but which are not being provided by the market; and (e) strong market monitoring and market power mitigation mechanisms would be required, including a proposed $1000/Mwh bid cap for energy and ancillary services in the day-ahead and real time markets, as well as bidding restrictions to deal with local market power problems.

2.2 Progress in the Development of Wholesale Market Institutions

Despite all of the political controversy surrounding these wholesale market reform initiatives, delays in implementing Order 2000 and the withdrawal of the proposed SMD rule in July 2005, a lot of progress has been made since 1996. As a direct result of FERC's "open access" Orders 888 and 889, all transmission-

3. *Regional Transmission Organizations,* 89 FERC ¶ 61,285 (1999). Order 2000 technically makes participation in an RTO voluntary, but there are carrots and sticks available to FERC that initially created significant pressure for utilities to join RTOs. Order 2000 does not mandate a particular organizational form for an RTO, however.

owning utilities in the U.S. (either directly or through an independent system operator or ISO) now have made available reasonably standardized cost-based transmission service tariffs to support the provision of transmission service on their networks to third parties; provide easily available real time information to third parties about the availability and prices of transmission service on their networks; are required to interconnect independent power producers to their networks; must make their best efforts to expand their transmission networks to meet transmission service requests when adequate capacity is not available to accommodate these requests; must provide certain network support services, including balancing services, to third parties using their networks; and are required to adhere to functional separation rules between the operators of their transmission networks and those who generate and market electricity using that network to mitigate abusive self-dealing behavior. These developments were essential to support entry of independent generators, expansions in wholesale trade, and retail competition as discussed further below.

FERC's RTO rule has also led to important changes in the industry. Table 1 and Figure 1 indicate that as of mid-2005, over 50% of the generating capacity in the U.S. is now operating within an ISO/RTO context (including Texas which is not subject to FERC jurisdiction) and other areas of the country are moving forward slowly with some type of ISO/RTO model. Moreover, most of these ISO/RTOs either have adopted the basic wholesale market principles reflected in the FERC SMD or (in the case of California) are in the process of adopting these institutions or (in the case of Texas) giving them serious consideration (FERC (2005), p.52). I will discuss the attributes of the existing SMD markets in the Northeast presently.

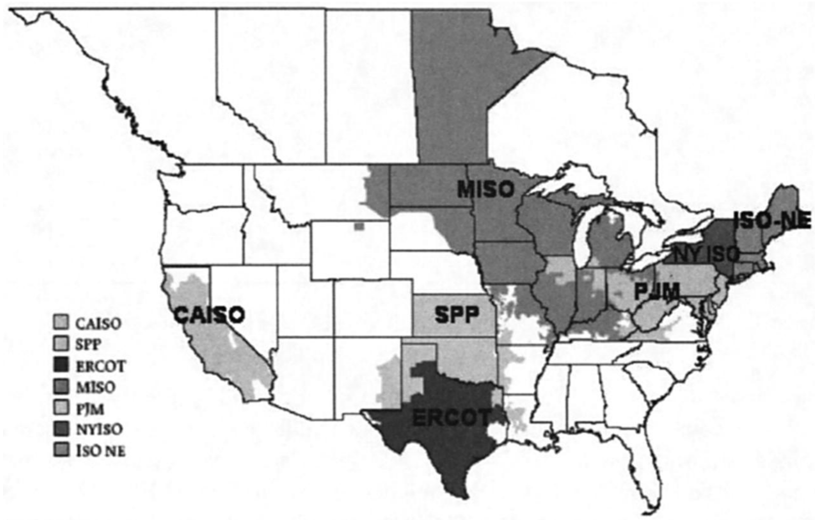
While FERC could not and did not order vertically integrated utilities to divest either their generating facilities or their transmission facilities to separate regulated from competitive lines of business, the combination of state initiatives

Table 1. Independent System Operators and Organized Wholesale Markets 2005

System Operator	Generating Capacity (MW)
ISO-New England (TRO)	31,000
New York ISO	37,000
PJM (expanded) (RTO)	164,000
Midwest ISO (MISO)	130,000
California ISO	52,000
ERCOT (Texas)	78,000
Southwest Power Pool (RTO)*	60,000
ISO/RTO Total	552,000
Total U.S. Generating Capacity	970,000

Sources: Individual ISO web pages and U.S. Energy Information Administration (EIAa) (various issues)
*Organized markets being developed.

Figure 1. ISOs and RTOs in the United States 2005



Source: U.S. Federal Energy Regulatory Commission (2005), p. 52.

and market opportunities has led to a considerable amount of restructuring of the ownership of existing generating plants. In 1996 there was about 750,000 Mw of utility-owned electric generating capacity in the U.S. of which investor-owned utilities (IOUs) accounted for about 580,000 Mw. After 1996, about 100,000 Mw of generating capacity was divested by IOUs and another 100,000 Mw transferred to unregulated utility affiliates to compete in the wholesale market. Moreover, between 1999 and 2004 about 200,000 Mw of new generating capacity was completed, about 80% of which was accounted for by unregulated generating companies (independent power companies and unregulated affiliates of utilities). See Table 2. More new generating capacity entered the market between 2001 and 2003 than in any three year period in U.S. history (FERC (2005), p. 59). Indeed, there was so much entry (and so little exit) that by 2003 there was excess generating capacity in most regions of the country. By 2004 over 40% of the power produced by investor-owned companies in the U.S. (i.e. excluding federal, state, municipal and cooperative generation) came from unregulated power plants, up from about 15% in 1996. After a decline in market liquidity following Enron's collapse, during 2004, trading in financial electricity products increased by a factor of ten (FERC (2005), p. 63).

The wholesale market design architecture articulated by FERC in its proposed SMD rule is also spreading, despite all of the controversy surrounding it and FERC's withdrawal of its proposed mandatory SMD rule. The primary features of this wholesale market design, built around a bid-based security

Table 2. New U.S. Generating Capacity (MW)

Year	Capacity Added (MW)
1997	4,000
1998	6,500
1999	10,500
2000	23,500
2001	48,000
2002	55,000
2003	50,000
2004	20,000
2005 (through May)	2,000
Total	Mw 220,000

Source: U.S. Energy Information Administration (EIAa and EIAb) (various issues).

constrained dispatch framework with locational or "nodal" pricing (LMP), has been or is being adopted in most of the regions that have created ISOs to operate regional transmission networks (SPP and Texas are the notable exceptions, although a nodal pricing system is being considered in Texas; FERC (2005), p. 52; *Megawatt Daily*, August 19, 2005, page 7). The SMD markets effectively integrate day-ahead, hour-ahead and real time energy prices, determined through a uniform price multi-unit auction framework, with the allocation of scarce transmission capacity. This makes the price of congestion quite transparent since it is reflected in the differences in locational spot energy prices in a way that reflects the physical attributes of the transmission network. Administrative rationing of scarce transmission capacity through the use of Transmission Line Relief (TLR) orders is, in principle, unnecessary, since scarce transmission capacity is rationed by prices and willingness to pay rather than through inefficient pro-rata administrative curtailments. Spot prices for energy reflect the marginal cost of congestion at each location on the network, and in New England and New York they reflect the marginal cost losses as well. Locational prices adjust smoothly to changes in supply and demand conditions on the network consistent with changes in the network's physical constraints. The creation and auctioning of Financial Transmission Rights (FTRs) that reflect the feasible set of allocations of generation to meet demand consistent with network transmission and related reliability constraints provides opportunities for market participants to hedge variations in congestion costs (Hogan (1992), Joskow and Tirole (2000)) and provide the financial equivalent of firm transmission service.

2.3 Attributes of SMD Markets Operating in the Northeast

The operation of the SMD markets can be illustrated with some examples from New England and New York. In New England the flow of power is typically from North to South, with import constraints into Boston and Southeastern Connecticut under certain supply and demand conditions and export constraints

Table 3. Day-Ahead Nodal Prices in New England

July 19, 2005, Hour 17
Load Zones Averages
$/MWH

Load Zone	Average Hour Price
Maine	130.56
New Hampshire	159.34
Vermont	195.65
Massachusetts (NE)	321.55
Massachusetts (SE)	162.12
Massachusetts (WC)	161.14
Rhode Island	142.44
Connecticut	165.96

Source: ISO New England Data Archive, http://www2.iso-ne.com/smd/operations_reports/hourly.php?warp=1.

from Maine and Rhode Island to the rest of New England. There are typically significant imports from Canada[4] and more limited imports and exports from and to New York. The associated transmission interconnection facilities are often congested as well. The introduction of an LMP-based wholesale market system has made this congestion transparent, yields associated price signals and facilitates the efficient allocation of scarce transmission capacity. In 2004, the average day-ahead LMP at the border between New Brunswick and Maine was about $53/Mwh and the average LMP in Connecticut was about $62/Mwh. The price difference reflects network congestion and thermal losses. The 17% difference in prices may not seem like much and perhaps not worth the effort. However, the annual average locational prices hide significant variations over time and across generation nodes as supply and demand conditions change. For example, Table 3 displays the average prices aggregated for each New England load zone for hour 17 on July 19, 2005, a hot day when the peak demand in New England hit a new record. It is evident that the price in Boston (NE Massachusetts) is two and a half times the price in Maine, reflecting import congestion into the Boston area. The zonal prices are much higher in Boston than in Connecticut at this hour even though on average during the year, Connecticut tends to be more congested than Boston. This shows that variations in spot prices for power reflect the fact that congestion patterns can change from one hour to another.

The price differences in New York State between New York City and Upstate New York are much larger than those observed for New England. In 2004 energy prices in New York City average nearly $90/Mwh while the average energy price in upstate New York was about $50, reflecting the import constraints into New York City and the high costs of the generating units located in the City (New York ISO (2005), p. 8).

4. Imports from outside the U.S. account for a very small fraction of aggregate U.S. electricity supplies.

2.4 Market Power and Its Mitigation

The development of competitive wholesale markets in the U.S. has been heavily influenced by concerns about market power. The potential for market power to be a particularly severe problem in electricity markets was recognized many years ago (Joskow and Schmalensee (1983), Chapter 12). It arises as a consequence of transmission constraints that limit the geographic expanse of competition, generation ownership concentration within constrained import areas, the non-storability of electricity, and the very low elasticity of demand for electricity (Joskow (1997), Borenstein (2002)). Generator market power was a serious problem for several years following the launch of the privatization, restructuring and competition program in the UK (Wolfram (1999)). Concerns about market power in the U.S. were reinforced by the events in California in 2000-2001 (Borenstein, Bushnell and Wolak (2002), Joskow and Kahn (2002)) where market power and the exploitation of market design imperfections contributed to the explosion in wholesale prices beginning in June 2000.

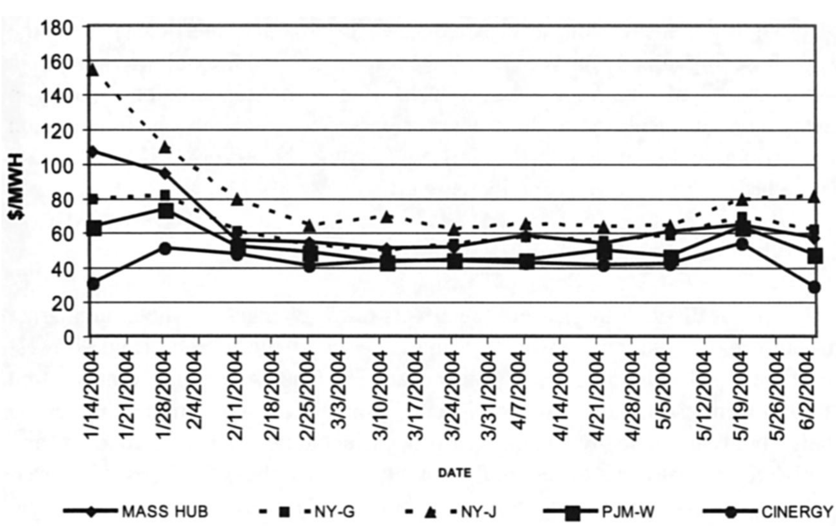
Market power monitoring and mitigation has been a central focus of FERC's wholesale market policies. However, despite all of the concerns about market power, the wholesale markets in the Northeast appear to be very competitive based on a variety of structural, behavioral and performance indicia (New York ISO (2005), pp. iii, vii; ISO New England (2005), pp. 98-106; PJM (2005), pp. 48-67). The primary exceptions emerge when supply and demand conditions lead to transmission constraints that create small "load pockets" within which the supply of generation is highly concentrated. However, market monitoring and mitigation protocols appear to have been reasonably successful in mitigating the ability of suppliers to exercise significant market power in these situations as well. Indeed, these measures may have been too successful, constraining prices from rising to competitive levels when demand is high, capacity is fully utilized, and competitive market prices should reflect scarcity values that exceed the price caps in place in the SMD markets (Joskow and Tirole (2005a)), a subject to which I shall return presently.

2.5 Intertemporal and Locational Price Convergence

Electricity is non-storable and supply and demand must be balanced with the ultimate in just in time production. This leads to significant volatility in spot market prices. However, the ability of suppliers and consumers to respond to large changes in real time prices is limited. This is especially true for suppliers or consumers in neighboring control/market areas. Many economic decisions in electricity markets are based on forward price signals in the hour-ahead, day-ahead, and longer forward markets. Market power is also more difficult to exercise in forward markets, making it attractive to move more price commitments into forward markets. Price convergence (intertemporal trading profits are arbitraged away) between the day-ahead, hour-ahead and real time markets is an important indicator of market performance. Price convergence in the SMD markets is reasonably good and has improved over time as these markets have been refined. Well designed virtual bidding opportunities can and have helped to improve price convergence and improve market efficiency (New York ISO (2005), pp. 10-16; ISO-New England (2005), p. 49)

Because the ISOs in the Northeast have adopted similar market designs, the integration of these markets has been facilitated and barriers to trade between these markets continue to decline, though "seams" issues continue to be an area where more work is needed (New York ISO (2005), pp. 66-73). The data in Figure 2 have been assembled to provide a simple picture of the interaction between these regional market areas as supply and demand conditions change. Figure 2 displays the day-ahead peak period (16 day-time hours on weekdays) prices for power at the Massachusetts hub, New York City (NY-J), the New York Hudson Valley (NY-G), the PJM West hub, and the Cinergy hub in the Midwest, for several days during the first six months of 2004. These hubs are all interconnected and power can be traded between them. If there were no congestion, no losses, efficient transmission pricing, and no institutional barriers to trade across these areas the prices would be equal to one another. In other words the Law of One Price would prevail. The general patterns of power flows in the Northeast are from the Midwest toward the East and from the North (Quebec, New Brunswick and Maine) to the South. New York City and Long Island are more frequently import constrained by transmission and related reliability constraints than other areas in the Northeast. It should be clear from Figure 2 that the Law of One Price does not prevail in Eastern electricity markets.

Figure 2. Day-ahead Peak Period Prices (2004) $/MWH



Source: Megawatt Daily, The McGraw-Hill Companies, (various issues).

The data in Figure 2 should be read starting at the far left with the locational day-ahead prices for mid-January 2004. It was extremely cold in the Northeast at this time, with temperatures falling to their lowest levels in over 50 years. As a result, demand for both natural gas and electricity were unusually high for this time of year. The electricity market in New England in particular was severely stressed despite the fact that peak demand was significantly lower than the quantity of installed capacity. Many generating plants were out of service due to routine maintenance, weather related problems, and the allocation of gas supplies between electricity generation and other uses (New England ISO (2004), FERC (2005), pp. 13-23). The demand for imported electricity into the Northeast from the Midwest increased and transmission capacity from the Midwest to the East became congested. We can see this in the separation of prices at various locations in mid-January. There was plenty of less costly generation in western Pennsylvania and the Midwest that could have served demand further east, but the transmission capacity to move the power east became constrained. Moving to the right in Figure 2 we see that as the weather returned to more normal levels as the year progressed the differences in locational prices compress significantly. New York City always has the highest prices because imports into New York City are frequently constrained by transmission limitations and some unique reliability considerations. The Mass Hub and Hudson Valley prices are about the same and often close to the PJM West prices. The Cinergy hub prices are always the lowest. Then as we move into June 2004 on the far right of Figure 2 we see the prices separate again as hot weather moves into the Northeast and demand for imported electricity rises again.

The markets in the Northeast and Midwest are clearly closely linked together, though spot energy prices exhibit locational differences as a result of congestion, losses, transmission service prices that exceed the marginal cost of providing transmission service (Joskow 2005b), and inefficiencies in the way these organized markets are linked together. Additional investment in transmission capacity, more effective utilization of the transmission capacity in place, more efficient pricing for transmission service, and enhanced integration and harmonization of the markets in New England, New York, PJM and MISO can reduce these price gaps and increase efficiency.

2.5. Wholesale Prices and Other Performance Indicia

It is difficult to measure the effects of the changes in wholesale market structure and institutions on wholesale market prices in the Northeast and Midwest since the mid-1990s when the reforms began. The wholesale markets that existed in 1996 were essentially "excess capacity" markets involving trades of electric energy between vertically integrated utilities which relied on regulated tariffs and captive retail customers to secure the capital costs for these facilities. Moreover, fuel prices, especially natural gas prices, have escalated dramatically since 1996 and hundreds of thousands of megawatts of unregulated generating capacity must

Table 4. Average Real Time Electric Energy Prices in New England Adjusted for Fuel Price Changes

	$/MWH	
Year	**Actual**	**Adjusted for Fuel Prices**
2000	45.95	45.95
2001	48.60	43.03
2002	46.55	37.52
2003	53.40	43.51
2004	54.44	43.33

Source: ISO New England (2005)

cover both their capital and operating costs through the sales of energy, ancillary services and capacity in competitive wholesale markets. Congestion costs are now transparent and revealed by differences in locational prices while they were once hidden in redispatch and unit commitment costs. There are some fragments of evidence about changes in wholesale market prices to consider, however.

A study comparing what prices would have emerged under cost of service regulation with the cost of buying that power in PJM's wholesale markets for three utilities in PJM, taking input cost changes into account, found that the cost of power purchased in PJM's wholesale market was lower than what the cost of that power would have been under continued cost of service regulation (Synapse Energy Economics (2004)). Wholesale market prices in New England, adjusted for changes in fuel prices, fell between 2000 and 2004 (See Table 4). Moreover, despite the fact that nominal wholesale market prices in the Northeast have risen along with fuel prices, the "all in" cost of power in the wholesale market (energy, ancillary services and capacity costs) between 2000 and 2004 was lower than the inflation adjusted regulated cost of generation service that was embedded to the regulated retail prices for many of the utilities in the Northeastern states in the late 1990s. For example, in the late 1990s, many northeastern utilities had average regulated costs of generation service in the 6 cent to 8 cent/kWh range (Joskow (2000)) or about 7 to 9.5 cents/kWh at current general price levels (without taking account of fuel price increases specifically). For the period 2002-2004, the all-in cost of power in the wholesale market in New York State outside of New York City and Long Island averaged about $50/Mwh. For New England the "all-in" price of wholesale power was about $50/Mwh over the period 2001-2004. In both cases this is significantly lower than the regulated cost of generation service embedded in retail prices prior to these reforms for many utilities in this region.

We should recognize, however, that cost-of-service regulation provided consumers with a hedge against fluctuations in fuel prices. In competitive markets the spot market price of electricity will reflect the marginal cost of the supplier that clears the market or the (much higher) value of unserved energy when the market is cleared on the demand side under "scarcity conditions" when capacity is fully utilized. Accordingly, if the marginal generating capacity that clears the market is natural-gas fired, the all-in market price of wholesale electricity will vary with variations in the price of natural gas, other things equal. Under cost-of-service regulation the all-in cost of generation service would be less sensitive to movements in natural gas prices in this case since the regulated costs of hydro, nuclear and coal-fired capacity would not vary directly with natural gas prices. Under cost-of-service regulation, natural gas price increases would have been reflected in retail prices in proportion to the fraction of generation accounted for by gas-fired capacity under cost-of-service regulation. Deregulation removes this hedge, making wholesale prices more sensitive to variations in the prices for fuel used by the marginal generating capacity that clears the market. If natural gas prices stay very high, it may turn out to be the case that in the short run, the costs of purchasing generation supplies out of competitive wholesale markets will be higher than the costs consumers would have paid under regulation as the rents associated with unregulated hydro, nuclear and coal capacity will now accrue to the owners of this capacity rather than to consumers as a consequence of the loss of this regulatory hedge. On the other hand, under regulation when there was excess capacity, prices rose to allow recovery of fixed costs while with competition excess capacity should lead to lower prices, other things equal. Consumers also were asked to pay for large generating plant construction cost overruns under regulation, while with competition it's the investors that bear construction cost overrun risks. We have too little experience to know how much these countervailing forces will affect generation service prices in the long run.

One of the benefits expected from the introduction of competitive wholesale markets was that it would provide incentives to improve the performance of the existing fleet of generating plants --- availability, non-fuel operating costs, heat rates (Joskow (1997)). Availability of generating capacity has increased over time in both New England and New York (ISO New England (2005), page 114; New York ISO (2005), p. 18). Equivalent availability factors increased significantly in PJM from 1994 to 1998 and have been roughly constant since then with some year-to-year variability (PJM (2005), p.168). Markiewicz, Rose and Wolfram (2004) find that the operating costs of generating plants fell more in states in the process of restructuring to support competition than in states which were not in the process of adopting restructuring programs. Bushnell and Wolfram (2005) find that divested generating plants and those subject to incentive regulation mechanisms improved their fuel efficiencies compared to their peers without high-powered incentives. Though the evidence is still limited, it tends to support the conclusion that competition has provided incentives to increase generating unit performance.

3. IMPROVING WHOLESALE MARKET PERFORMANCE

While there has certainly been a lot of progress made in creating good competitive wholesale market institutions, and there has been a lot of valuable learning from experience, there is still a lot more work to do. The necessary reforms go well beyond modifications in the details of Orders 888/889 as some have suggested is the appropriate focus of future FERC policy initiatives. Let me identify and discuss very briefly four areas where I think significant performance improvements need to be made.

3.1 Incentives to Invest in New Generating Capacity

Despite the enormous quantity of new generating capacity that entered service between 2000 and 2004, and the existence of excess capacity in most regions of the country, policymakers are now very concerned about future shortages of generating capacity resulting from retirements and inadequate investment. Many of the merchant generating companies that made these investments subsequently experienced serious financial problems and several went bankrupt. The liberal financing arrangements available to support these projects during the financial bubble years are no longer available and project financing for new generating plants is difficult to arrange unless there is a long term sales contract with a creditworthy buyer to support it. Rising natural gas prices have changed the economic attractiveness of the combined-cycle gas turbine technology that has dominated the fleet of new plants. The quantity of new generating capacity coming out of the construction pipeline is falling significantly (see Table 2). Very little investment in new merchant generating capacity is being committed at the present time, aside from wind and other renewables that can obtain favorable tax treatment and other financial and contractual incentives. System operators in the Northeast and California are projecting shortages and increases in power supply emergencies three to five years into the future, recognizing that developing, permitting and completing new generating plants takes several years. Unlike the situation in England and Wales, the U.S. does not have large amounts of mothballed capacity that can come back into service quickly as prices rise.

On the one hand, a market response that leads prices (adjusted for fuel costs) and profits to fall and investment to decline dramatically when there is excess capacity, is just the response that we would be looking for from a competitive market. For 25 years prior to the most recent market reforms the regulated U.S. electric power industry had excess generating capacity which consumers were forced to pay for through regulated prices. The promise of competition was that investors would bear the risk of excess capacity and reap the rewards of tight capacity contingencies, a risk that they could try to reallocate by offering forward contracts to consumers and their intermediaries. At least some of the noise about investment incentives is coming from owners of merchant generating plants who would just like to see higher prices and profits. On the other hand, numerous analyses of the performance of organized energy-only wholesale markets indicate that they do not appear to produce enough net revenues to support investment in new generating capacity in the right places and consistent with the administrative reliability criteria that are still applicable in each region. Moreover, while capacity obligations and associated capacity prices that are components of the market designs

Table 5. Theoretical Net Energy and Ancillary Services Revenue For A New Combustion Turbine Peaking Plant (PJM)

	$/MW- Year
Year	***Net* Energy and Ancillary Services Revenue**
1999	64,445
2000	18,866
2001	41,659
2002	25,622
2003	14,544
2004	10,453
Average	29,265
Annualized 20-year Fixed Cost ~ $70,000/Mw/year	

Source: PJM (2005)

in the Northeast produce additional net revenue for generators over and above what they get from selling energy and ancillary services, the existing capacity pricing mechanisms do not appear to yield revenues that fill the "net revenue" gap. That is, wholesale prices have been too low even when supplies are tight.

The experience in PJM is fairly typical. Table 5 displays the net revenue that a hypothetical new combustion turbine would have earned from the energy market plus ancillary services revenues in PJM if it were dispatched optimally to reflect its marginal running costs in each year 1999-2004. In no year would a new peaking turbine have earned enough net revenues from sales of energy and ancillary services to cover the fixed costs of a new generating unit and, on average, the scarcity rents contributed only about 40% of the costs of a new peaking unit. Based on energy market revenues alone, it would not be rational for an investor to investment in new combustion turbine or CCGT capacity in PJM. PJM has always had capacity obligations which it carried over into its competitive market design and in theory capacity prices should adjust to clear the market (Joskow and Tirole (2005b)). However, even adding in capacity revenues, the total net revenues that would have been earned by a new plant over this six year period would have been significantly less than the fixed costs that investors would need to expect to recover to make investment in new generating capacity profitable.

This phenomenon is not unique to PJM. Every organized market in the U.S. exhibits a similar gap between net revenues produced by energy markets and the fixed costs of investing in new capacity measured over several years time (FERC (2005), p. 60; New York ISO (2005), pages 22-25). There is still a significant gap when capacity payments are included. The only exception appears to be New York City where prices for energy and capacity collectively appear to be sufficient to support new investment, though new investment in New York may be much more costly than assumed in these analyses (FERC (2005), page 60). Moreover, a large fraction of the net revenue there comes from capacity payments rather than energy market revenues (New York ISO (2005), p. 23).

I have discussed elsewhere some of the regulatory, system operation and market imperfections that seem systematically to lead organized wholesale energy markets to produce inadequate incentives for new investment in generation consistent with prevailing engineering reliability criteria (Joskow (2005a), Joskow and Tirole (2005b)). The problems include: (a) price caps on energy supplied to the market and related market power mitigation mechanisms that do not allow prices to rise high enough during conditions when generating capacity is fully utilized to provide energy and operating reserves to meet reliability constraints. Under these conditions supply and demand should be balanced by responses on the demand side to high prices that reflect the value of lost load, producing significant competitive scarcity rents for generators; (b) price caps on capacity payments in the market designs that incorporate capacity obligations and capacity prices; (c) actions by system operators that have the effect of keeping prices from rising fast enough and high enough to reflect the value of lost load during operating reserve emergencies when small changes in system operating procedures can lead to very large changes in prices and scarcity rents needed to cover fixed costs; (d) reliability actions taken by system operators that rely on Out of Market (OOM) calls on generators that pay some generators premium prices but depress the market prices paid to other suppliers; (e) the absence of adequate spot market demand response to allow prices to play a larger role in balancing supply and demand under tight supply conditions; (f) payments by system operators to keep inefficient generators in service due to transmission and related constraints rather than allowing them to be retired or be mothballed, (g) regulated generators operating within a competitive market that have poor incentives to make efficient retirement decisions, depressing market prices for energy and (h) engineering reliability rules that have not been harmonized with market mechanisms and may implicitly impose costs of meeting reliability standards that are significantly greater than what consumers would be willing to pay in a well functioning competitive market.

The "resource adequacy" problems arising from imperfections in spot energy markets are now widely recognized by policymakers. FERC's proposed SMD rules contained requirements that system operators implement mechanisms to assure resource adequacy. Efforts are being made to reform capacity obligations and associated market mechanisms to try to deal with them (Cramton and Stoft (2005)). More could be done to reform spot energy markets to allow prices to rise to appropriate competitive levels when generating capacity is fully utilized, to expand demand side participation in the spot market, and to better harmonize reliability rules and reliability actions taken by system operators with market mechanisms.

3.2 Improve the Framework for Supporting Transmission Investment and Expanding Effective Transmission Capacity

As wholesale markets have developed congestion on the transmission network has increased significantly (Joskow (2005b, 2005c)). Investment in transmission capacity has not kept pace with the expansion in generating capacity and changes in trading patterns (Hirst 2004). Transmission congestion and related reliability constraints create load pockets, reducing effective competition among generators and leading policymakers to impose imperfect market power mitigation rules that create other distortions.

In addition to the effects of transmission congestion on wholesale power prices and the social costs of congestion, a congested transmission network makes it more challenging to achieve efficient wholesale market performance. Congestion increases market power problems and the use of highly imperfect regulatory mitigation mechanisms to respond to them. Congestion makes it more challenging for system operators to maintain reliability using standard market mechanisms, leading them to pay specific generators significant sums to stay in the market rather than retire and to rely more on OOM calls that depress market prices received by other suppliers (FERC (2005), pp. 6, 23, 61). In New England, the amount of generating capacity operating subject to reliability contracts with the ISO has increased from about 500 Mw in 2002 to over 7,000 Mw projected (including pending contracts) for 2005 (ISO-New England (2005), p.80).[5] These responses to transmission congestion undermine the performance of competitive markets for energy, exacerbate the net revenue problem discussed above, and lead to additional costly administrative actions to respond to market imperfections resulting from transmission congestion.

The existing framework for supporting transmission investment is seriously flawed. Regulatory responsibilities are split between the states and the federal government in sometimes mysterious ways (Joskow (2005b)). FERC initially supported a flawed "merchant investment" model (Joskow and Tirole (2005a)) and confused issues of who pays for transmission upgrades with questions about whether such upgrades would be mediated through market mechanisms (e.g. in return for FTRs) or regulatory mechanisms or a combination of both. Transmission investments driven by reliability considerations and transmission investments driven by congestion cost reductions are inherently interdependent but have been treated by FERC and some system operators as if they were completely separable (Joskow (2005c)). The U.S. does not even collect statistics on transmission investment and transmission network performance that are adequate to evaluate the performance of the network (U.S. Energy Information Administration (2004)). Despite promoting performance based regulation for transmission as provided for in Order 2000, there has been little progress in developing and applying a coherent incentive regulation framework in practice. Much of the increase in transmission investment that is reported to have occurred is associated with interconnections of new generators and associated network reinforcements to meet reliability criteria. There has been little if any investment in transmission facilities to increase interregional transfer capability.

5. FERC has ordered the ISO to replace these agreements with a locational capacity market mechanism built around an administratively determined "demand curve" for generating capacity. However, implementation has now been delayed until at least October 2006.

While the situation is improving with the adoption of more comprehensive transmission planning and investment processes in New England, PJM and the MISO, the transmission investment and regulatory framework has a long way to go before is will stimulate needed investments required to improve network performance and to create a transmission network platform that supports efficient competitive markets for power with less regulation and fewer administratively determined reliability contracts.

3.3 Continue to Reduce "Seams" Problems that Create Barriers to Trade Between Market Areas

The wholesale markets operating on the three synchronized U.S. transmission networks (Eastern Interconnection, Western Interconnection, and ERCOT (Texas)) are regional markets whose effective geographic expanses have grown over time. However, there remain opportunities to further reduce barriers to trade and to expand their geographic scope. The differences in wholesale market prices observed between different areas in the Northeast and Midwest (Figure 2) are partially a consequence of transmission network congestion. However, the price differences are also caused by regulated transmission prices that create an inefficient wedge between energy prices in different areas. They also reflect incompatibilities in the wholesale market mechanisms in different ISOs that limit trading between the spot markets operated in each area. Long distance trades in energy can still incur multiple transmission charges that include "pancaked" sunk cost allocations that make efficient trades uneconomical. Differences in the timing of the bidding and market clearing mechanisms and asymmetric treatment of generators in different control areas can further inhibit short-term trading opportunities and lead to inefficient allocation of scarce transmission capacity. The efforts by New England and New York and by PJM and the MISO to reduce these trading barriers are admirable and these efforts should be expanded to other regions.

3.4 Increase Demand Response

In markets for most goods and services when demand grows and supply capacity constraints are reached prices rise to ration demand to match the capacity available to provide supplies to the market. In electricity markets, however, as generating capacity constraints are reached, relatively little demand can be rationing by short term price movements and, instead, must by rationed administratively with rolling blackouts. The possibility of broader uncontrolled cascading blackouts and regional network collapses further exacerbates this problem, necessarily leads to regulatory requirements specifying operating reserves, operating reserve deficiency criteria and associated administrative actions by system operators to balance the system to meet voltage, stability and frequency requirements in an effort to avoid cascading blackouts (Joskow and Tirole (2005b)). The challenges faced by network operators to maintain system reliability and avoid non-price rationing of demand would be reduced if additional demand-side instruments were at its disposal. These include more customers who can see and respond to rapid changes in market prices and expanded use of price-contingent priority rationing contracts (Chao and Wilson 1987).

Too little demand side response has been developed to date. In New England, with a peak demand of over 26,000 Mw only a few hundred Mw is available to the system operator for use during power supply emergencies (ISO New England (2005), p.91). New York, with a peak demand of over 30,000 Mw has done better with about 1700 Mw of "quick" demand response (New York ISO (2005)). The demand response instruments that are available are poorly integrated with spot markets and are likely to have the effect of depressing prices inefficiently. Moreover, the prices that are paid for demand response or the prices that can be avoided by responding to price signals are too low compared to the long run cost of carrying generating capacity reserves to meet planning reserve margins. Improving demand response should be given higher priority in wholesale market design.

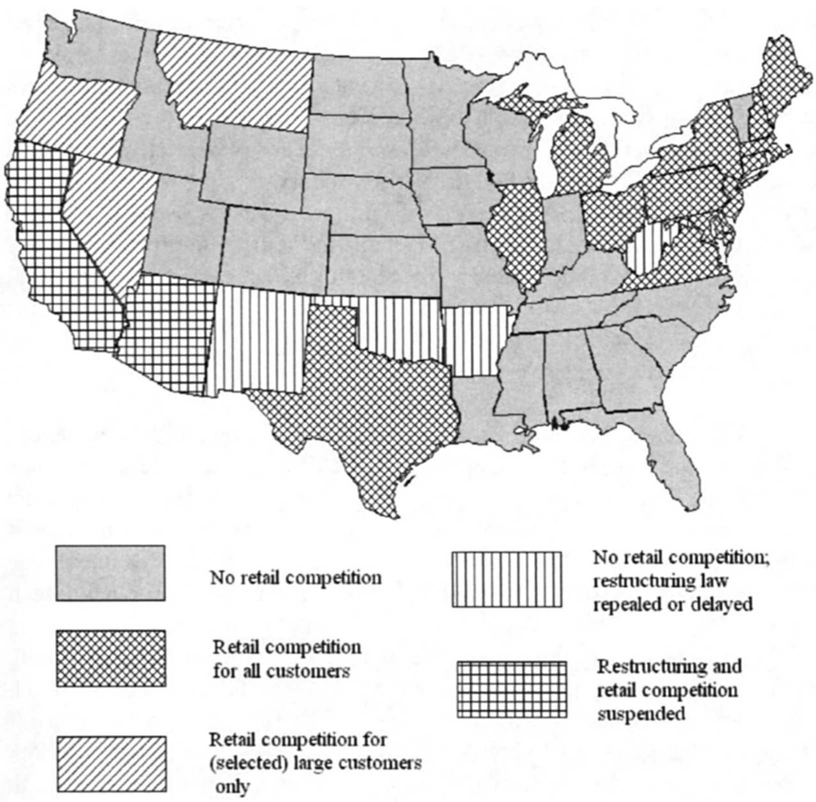
4. RETAIL COMPETITION

In the policy arena, the primary selling point for competition in electricity in most states has been the prospect for *retail competition* or *retail customer choice* to lead to lower *retail* electricity prices. My assessment of the status of retail competition among the states is displayed in Figure 3. All of the states, except for Texas, that have implemented and sustained comprehensive retail competition programs are in the Northeast and upper Midwest. These states had regulated retail prices that were among the highest in the U.S. in 1996 (Joskow (2000)). California suspended its retail competition program in 2001 as did Arizona (where it never really got started). Three states have programs that are limited to selected industrial customers. All of the other states either withdrew their existing plans to introduce retail competition after the California electricity crisis or never adopted a retail competition plan. There appears to be little interest today in those states without retail competition to introduce it and some pressure in states that have it to repeal it.

With a retail competition program, an electricity customer's bill is "unbundled" into regulated non-bypassable "delivery" component with a price P_R (transmission, distribution, stranded cost recovery, retail service costs to support default services) and a competitive component with a price P_C (generation service, some retail service costs, and perhaps an additional "margin" to induce customers to shop). The customer continues to buy the regulated delivery component from the local distribution company but is free to purchase the competitive component from competing retailers which I will refer to as retail Electricity Service Providers (ESP).

In most jurisdictions that have introduced retail competition programs, the incumbent distribution company is required to continue to provide regulated "default service" of some kind to retail consumers who do not choose an ESP

Figure 3. Status of retail competition and restructuring reforms 2005



Source: Author's assessments.

during a transition period of from five to ten years. The terms and conditions of default service vary across the states, but typically default service prices have been calculated in the following way. Regulators start with the incumbent's prevailing regulated cost of generation service. A fraction of this regulated generation cost component may be determined to be "stranded generation costs" that can be recovered from retail consumers over some time period and is included in the regulated price of delivery services P_R. The residual is then used to define the initial "default service" price P_C or the "price to beat" by ESPs seeking to attract customers from the regulated default service tariffs available from the incumbent utility. The value of P_C is then typically fixed for several years (sometimes with adjustments for fuel prices). After the transition period the default price is expected to equal at least the competitive market value of providing competitive retail services to consumers.

In many states the regulated default service price was either set or eventually fell below the comparable cost of power in the wholesale market. In some cases, rising wholesale prices caused by higher gas prices erased or reversed the gap between the default price and the wholesale price. For example, in Pennsylvania, PPL has a default price of 5.5 cents/Kwh for residential customers that is based on a formula defined when retail competition was initiated in Pennsylvania in 2000.[6] The forward *wholesale* price for power delivered at PJM West for Calendar year 2006 (16 hours per day for six days per week) was about 8 cents/kWh on August 23, 2005. PPL's default price is not scheduled to rise to market levels until 2010. Obviously, ESPs will find it difficult profitably to buy power at 8 cents and sell it at under 5.5 cents to attract customers away from default service.

4.1 Customer Switching Patterns

Most states that have introduced retail competition have experienced fairly similar and generally disappointing switching patterns. Relatively few residential and small commercial customers switch to ESPs and the migration from the incumbent's default service to competitive service for all but the largest customers has been very slow (Joskow 2005a). Larger industrial customers have been more likely to switch to ESPs and have done so much more quickly than residential customers.

To provide a typical example, Table 6 displays the retail switching statistics for Massachusetts, one of the first states to introduce retail competition, for February 2004 and May 2005. Retail competition was introduced for all customers in Massachusetts in early 1998, so consumers have had seven years to adapt to it. Only about 7% of the residential customers accounting for 6% of residential consumption have switched. There are few ESPs offering service to residential and small commercial customers active in the market. Over a similar period of time, over 50% of the residential customers switched to competing suppliers in England and Wales and there are several competing retail suppliers offering service to residential (domestic) customers there. Switching in Massachusetts has been greater among small, medium and large commercial customers, with the largest electricity consumers in each category being more likely to switch. After seven years of retail competition, only 8% of the total retail customers accounting for 34% of electricity consumption have switched to competitive suppliers. However, switching among all classes of customers (and the number of ESPs seeking customers) now seems to be increasing since the regulated default service (called standard offer service in Massachusetts) ended in March 2005 and all default service prices began to reflect wholesale market values. This appears to be the reason that we see a big jump in switching activity between February 2004 and May 2005.

6. *Megawatt Daily*, August 18, 2005, pages 1 and 10.

Table 6. Retail Competition in Massachusetts February 2004 and May 2005

Retail Choice Began March 1998

Customer Type	% of Load Served by ESP's February 2004	May 2005
Residential	2.6	6.1
Small Commercial/Industrial	10.8	19.3
Medium Commercial/Industrial	17.0	22.2
Large Commercial/Industrial	48.3	63.3
Total	22.6	34.0

Source: Massachusetts Department of Energy Resources (2005)

Texas has had the most successful U.S. retail competition program as measured by customer switching activity. Retail competition began officially in Texas in January 2002, though there was a pilot program implemented before that and customers who had switched before the official program began could stay with the ESPs they had chosen. Texas adopted a retail competition program similar to that in the UK. Regulated default service was limited to smaller residential and commercial customers, the price for this service was set at (or above) wholesale market levels, the "price to beat" left an additional margin for competitive suppliers, and incumbents were given incentives to shift their retail customers to competitive suppliers. By June 2005 about 15% of the residential customers had switched to ESPs and the fraction continues to grow (Public Utility Commission of Texas (2005)). For commercial customers, 20% of the customers and 46% of the load had switched to ESPs by June 2005, while 38% of the largest customers, accounting for 63% of the load, had switched to an ESP. Virtually all of the largest customers have negotiated competitive contracts either with the retailing affiliate of their incumbent utility or an unaffiliated ESP. Unlike Pennsylvania, where the fraction of customers served by ESPS has declined over time (not the sign of a successful product), retail switching shows a monotonic increasing trend in Texas. Texas is also the state that has the largest number of active ESPs competing to sell service to retail consumers.

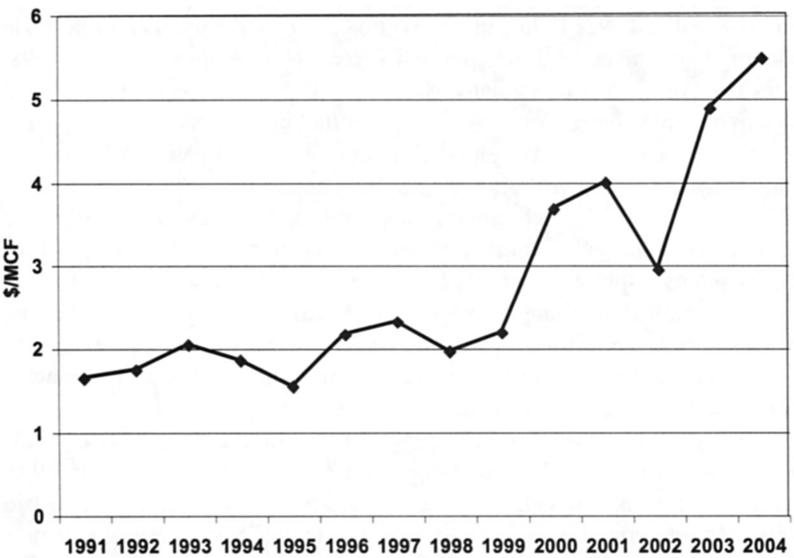
The biggest problem facing ESPs is "competition" from regulated default service and the unpriced option to go and return from regulated to competitive retail prices and back again that is often embedded in it. If regulated default service prices are set below the comparable wholesale market price of power, ESPs will not be able to compete for retail customers. Moreover, allowing customers that choose to take service from an ESP to return to a regulated tariff when wholesale prices are high, without being charged an appropriate price for this option, seriously undermines the development of retail competition. This leads to a very unstable customer base for ESPs, and undermines incentives for ESPs to enter into long term forward contracts or acquire generating assets to support their retail supply portfolios. While I remain unconvinced that residential and small commercial consumers are likely to benefit from retail competition, compared to simply relying on the local distribution company to buy power for them in the wholesale market, the worst of all worlds is the adoption of policies that rely on retail competition evolving but make it uneconomical for customers to switch to an ESP. Policymakers need to choose whether or not they really have faith in retail competition and adopt policies that either support its development if they do or rely instead on a wholesale competition model in which distribution companies procure power competitively if they don't.

5. RETAIL PRICE PATTERNS

The promise of lower prices was the political selling point for competition in most states. Policymakers in many states are asking whether or not competition is benefiting consumers through lower prices. We should be able to answer their questions. But lower compared to what? Lower than they were in 1996? Lower than they would have been if the regulated monopoly regime had continued? Lower in real dollars or nominal dollars? Policymakers were not particularly clear about the relevant comparisons as they were selling or opposing pro-competition reforms over the last decade. Given changes in fuel prices, demand, technology and environmental constraints, the only sensible comparison is between what prices are at a point in time under a competitive institutional framework and what they would have been if the prevailing regulated monopoly framework had continued. Unfortunately, this is a difficult counterfactual comparison to make. It is complicated by the large increase in natural gas prices (Figure 4) and the entry of almost 200,000 Mw of new mostly gas fired generation since 1998 (Table 2). Under a competitive model retail prices reflect the aggregation of competitive components (generation and retail supply) and regulated components (transmission and distribution). Moreover, since the industry structure and regulatory frameworks have varied from state to state, the answer to this question could very depend on variations in the nature of regulatory institutions and the performance of regulated firms in different states.

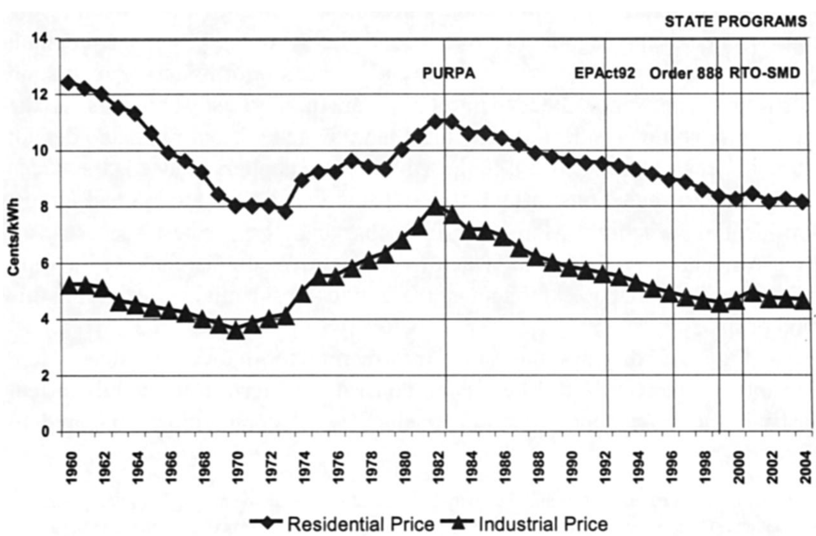
To place the analysis that follows in context, Figure 5 displays a time series of average *real* residential and industrial electricity prices from 1960 through 2004 for the U.S. as a whole. Average real U.S. electricity prices fell virtually continuously from the early 20th century until about 1972. The combination of rising inflation, rising nominal interest rates, the exhaustion of scale economies in generation, and large increases in fuel prices in connection to the oil shocks in 1973 and 1979 reversed this historical trend. As fuel prices, inflation and nominal interest rates began to fall in the early 1980s, real electricity prices began to fall as well (Joskow (1974, 1989)). While some trace the start of policy initiatives to promote competition to the implementation of PURPA in the early 1980s, it is widely believed that PURPA, as it was implemented in the states with the greatest enthusiasm for it, led to higher rather than lower retail prices (Joskow (1989)). Accordingly, it would be incorrect to conclude from Figure 5 that there is a causal

Figure 4. Average natural gas wellhead prices 1991-2004, $/MCF



Source: U.S. Energy Information Administration (EIAc, EIAd) (various issues).

Figure 5. Average real U.S. electricity prices 1960-2004 ($2000)



Source: U.S. Energy Information Administration (EIAd, EIAa) (various issues), nominal prices adjusted using the GDP deflator.

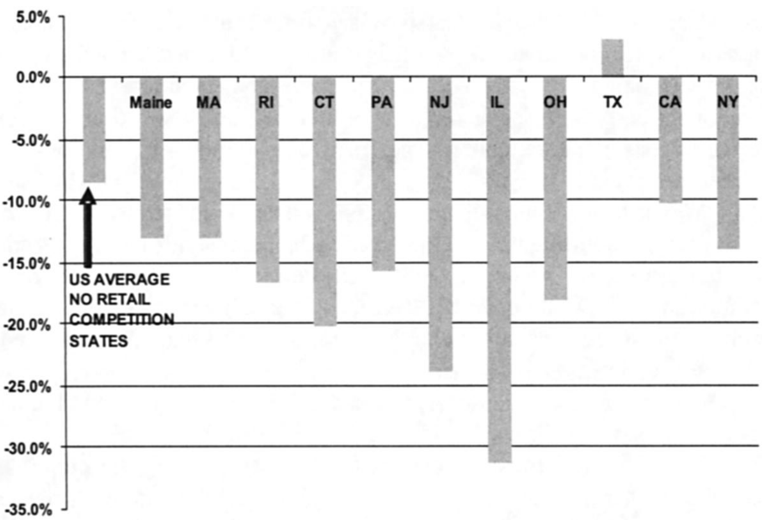
relationship between the implementation of PURPA and the renewed trend of lower real electricity prices. The major contemporary competitive initiatives began to be realized after 1996 with Orders 888 and 889, the retail and wholesale restructuring initiatives in California and several Northeastern states in 1998, the associated divestiture of regulated generating plants that became unregulated Exempt Wholesale Generators (EWG) as permitted by reforms contained in the Energy Policy Act of 1992, the entry of a large amount of new EWG capacity in many areas of the country following the state and federal reforms after 1996, and the subsequent FERC and state reforms that I have already discussed. There is certainly no noticeable dramatic change in the trend of average real U.S. electricity prices displayed in Figure 5 that can be readily associated with these post-1996 reforms. If anything, the rate at which real electricity prices fell seems to have declined as these reforms were implemented. Accordingly, the aggregate time series data alone tell us little about the effects of competition and regulatory reforms on the prices paid by consumers.

We can slice the data another way and compare the trends in retail prices in states that adopted retail competition reforms, often along with other restructuring reforms that supported the development of competitive wholesale markets, with the price trends in states that did not adopt such reforms. Figure 6 compares the changes in real residential electricity prices for states that introduced retail competition and those that did not between 1996 and 2004.[7] It is evident that real residential prices fell more in states that implemented retail competition programs than in those that did not. Only Texas shows an increase in residential prices. However, in light of the discussion in the last section, if the lower prices in retail competition states are due to competition reforms they are a consequence of the negotiations over stranded cost recovery, regulated default service pricing, lower wholesale market and perhaps reforms in the regulation of distribution networks rather than retail competition per se. This must be the case because so few residential customers have switched from regulated default service to service provided by competitive retail suppliers. Indeed, the states with the largest reductions in real prices (Illinois and New Jersey) had almost no residential switching. Moreover, Texas has had the greatest success with getting residential customers to switch to competitive suppliers and is the only retail competition state to exhibit an increase in real residential prices during this period of time.

Figure 7 displays the same information for industrial prices. Here the results are more mixed. There is no consistent pattern in the trends in real industrial prices for states that implemented retail competition compared to

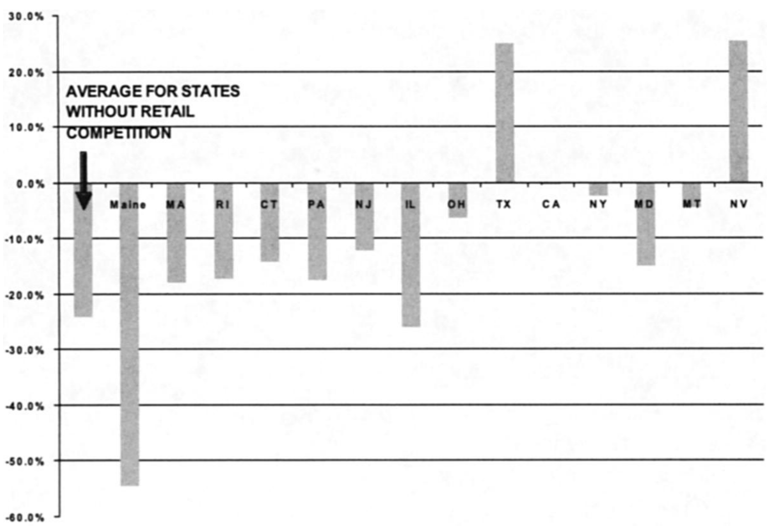
7. One important caveat to this and the analysis that follows should be noted. The retail price data may have imperfections. Reported retail price data ultimately rely on reports filed with the U.S. Energy Information Administration (EIA). It is fairly clear that it took some time for EIA to take full and appropriate account of the impacts of retail competition on the price data reported to them. However, by 2004 EIA seems to have solved these reporting problems so that the comparisons between 1996 prices before there was any retail competition and 2004 prices should be valid.

Figure 6. Changes in real residential prices with and without retail competition 1996-2004 (%)



Source: Calculated from U.S. Energy Information Administration (EIAa, EIAb, EIAd) (various issues), adjusted for changes in the consumer price index.

Figure 7. Changes in real industrial prices 1996-2004 with and without retail competition (%)



Source: Calculated from U.S. Energy Information Administration (EIAa, EIAb,EIAd) (various issues), adjusted for changes in the Consumer Price Index.

those that did not. Indeed, real industrial prices fell more on average in states without retail competition than in those states that introduced it for industrial customers. States like Nevada and Montana introduced retail competition for industrial customers in a way that provided little protection from changes in wholesale market conditions, while other states provided hedged default service prices of varying durations and with varying terms and conditions. Moreover, the generation mix and the associated effects of fuel prices on generation costs, entry of unregulated generators, and changes in wholesale market conditions varies from region to region.

We can begin to analyze the impacts of wholesale and retail market reforms on electricity prices in different states using additional time series and cross-sectional data that measure these variables and allow us to control for various cost drivers. The following analysis is what I believe is the first, admittedly crude, empirical analysis to examine more systematically the effects of cost drivers and competitive policy reforms on retail prices across states and over time. I view it as more of a systematic data analysis exercise than an effort to estimate a complete model of retail prices. It is a starting point that I hope will lead to more refined analyses.

I have collected a state-level panel data set covering the period 1970 through 2003[8] that includes variables measuring residential and industrial retail prices, various cost drivers, and variables measuring the intensity of various "deregulatory" initiatives, starting with PURPA. The data are discussed in more detail in the Appendix. In the spirit of Stigler and Freidland (1962), I estimate the following price equation for residential and commercial customers using state-level data for the periods 1970–2003 and 1981-2003 that include variables measuring cost drivers and those measuring various policy initiatives. The sample begins well before the introduction of the policy treatments so that the coefficients of the cost drivers should be well established.

$$\begin{aligned} P_{itj} = \beta_0 + \beta_1 RFC_{it} + \beta_2 HYDRO_{it} + \beta_3 NUCLEAR_{it} + \\ \beta_4 RYield_t + \beta_5 SIZE_{it} + \beta_6 PURPA_{it} + \beta_7 EWG_{it} + \\ \beta_8 RETAIL_{it} + \mu_i + \nu_t + \varepsilon_{it} \end{aligned} \tag{1}$$

where:

i indexes states
t indexes years
j is either the residential price (r) or the industrial price (i)
μ_i is a state specific error
ν_t is a time specific error
ε_{it} is an iid random error

8. The data for some of the right hand side variables are not yet available for 2004 as this is written.

and the variables are defined as:

P:	average retail residential or industrial price.
RFC:	average real fossil fuel price per kWh of total electricity supplied in each state over time.
RYield:	Real yield on electric utility debt over time.
HYDRO:	share of total electricity supplied coming from hydroelectric generation in each state over time.
NUCLEAR:	share of total electricity generation coming from nuclear plants in each state over time.
PURPA:	share of total electricity generation coming from PURPA qualifying facilities (QF) in each state beginning with 1985.
EWG:	share of electricity generated by unregulated generators in each state beginning in 1998.
RETAIL:	a dummy variable indicating whether or not a state had introduced retail competition in a particular year — beginning in 1998.

Table 7. Residential Price Equations 1970-2003 (standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.51	0.51	0.48
	(0.019)	(0.019)	(0.019)
HYDRO	-0.20	-0.16	-0.36
	(0.077)	(0.095)	(0.099)
NUCLEAR	0.39	0.38	0.45
	(0.054)	(0.056)	(0.056)
YIELD	0.042	0.043	0.047
	(0.002)	(0.002)	(0.002)
SIZE	-0.13	-0.13	-0.11
	(0.0044)	(0.0048)	(0.0063)
PURPA	0.43	0.42	0.61
	(0.078)	(0.079)	(0.084)
EWG	-0.24	-0.23	-0.23
	(0.058)	(0.058)	(0.057)
RETAIL	-0.24	-0.25	-0.21
	(0.042)	(0.042)	(0.042)
R^2 (corrected)	0.74	0.61	0.62

Source: See text and appendix.

Table 8. Residential Price Equations 1981-2003 (standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.24	0.19	0.048
	(0.031)	(0.032)	(0.029)
HYDRO	-0.064	0.125	-0.36
	(0.11)	(0.153)	(0.137)
NUCLEAR	0.21	0.136	0.082
	(0.071)	(0.073)	(0.056)
YIELD	0.06	0.056	0.027
	(0.0046)	(0.0047)	(0.004)
SIZE	-0.18	-0.21	-0.1
	(0.0077)	(0.0088)	(0.0089)
PURPA	0.22	0.122	0.288
	(0.09)	(0.092)	(0.082)
EWG	-0.19	-0.16	-0.16
	(0.054)	(0.054)	(0.048)
RETAIL	-0.24	-0.25	-0.126
	(0.039)	(0.038)	(0.034)
R^2(corrected)	0.66	0.73	0.79

Source: See text and appendix.

Table 7 presents the regression results for the retail price model for residential prices for the period 1970 through 2003 using (1) generalized least squares, (2) state-specific fixed effects and (3) and state-specific fixed effects plus a time trend to correct for potential serial correlation. Table 8 presents the results for the same specifications for a shorter panel covering the period 1981-2003. Tables 9 and Table 10 present the same estimation results for industrial prices.

Let us look first at Tables 7 and 8 where the results for the residential price regressions are displayed. The results for the three alternative specifications and the two time periods are quite similar. For the residential price regressions the cost drivers generally behave as expected, recognizing that the fixed-effects regressions identify the coefficients from "within-state" variation over time. Increases in real fuel prices lead to higher retail electricity prices. More hydroelectric generation leads to lower retail prices. More nuclear capacity leads to higher retail prices reflecting the high capital costs of nuclear plants and their contribution to stranded cost recovery factors in states that introduced retail competition. Higher real interest rates also are associated with higher residential prices.

Turning to the policy variables, the more important is PURPA (QF) generation the higher are retail prices, consistent with the earlier literature (Joskow (1989)). The more important is unregulated wholesale market power supplies (EWG) the lower are retail prices. EWG generation has potential effects

Table 9. Industrial Price Equations 1970-2003 (standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.74	0.73	0.68
	(0.019)	(0.02)	(0.019)
HYDRO	-0.264	-0.13	-0.535
	(0.078)	(0.10)	(0.10)
NUCLEAR	0.20	0.22	0.42
	(0.071)	(0.055)	(0.056)
YIELD	0.034	0.034	0.043
	(0.0054)	(0.002)	(0.002)
SIZE	-0.4	-0.4	-0.3
	(0.034)	(0.035)	(0.03)
PURPA	0.41	0.38	0.69
	(0.08)	(0.081)	(0.083)
EWG	-0.26	-0.24	-0.22
	(0.059)	(0.059)	(0.057)
RETAIL	-0.16	-0.17	-0.12
	(0.043)	(0.043)	(0.042)
R^2 (corrected)	0.62	0.60	0.64

Source: See text and appendix

in both states with retail competition and those without it since EWG generation is a substitute for the generation a vertically integrated utility might produce from its own power plants. Note that there is substantial EWG generation in the Southeast where there is no retail competition. Finally, the coefficient on the retail competition dummy variable is consistently negative. The measured effect is that retail competition reduces retail prices on the order of 5% to 10% at the means of the sample.

Turning to Tables 9 and 10, the estimated relationships are generally similar for the industrial price equations as for the residential price equations. However, the retail competition effect, on the order of 5%, is numerically smaller at the means of the sample and is estimated less precisely than for the residential price equations.

These results are consistent with the view that PURPA was bad for consumers from a retail price perspective, but that wholesale competition, captured with the EWG variable, and retail competition have both been associated with lower retail prices once the major input cost drivers are controlled for. These results must be interpreted with care, however. There are several caveats. First, the price data are likely to be imperfect. Reported retail price data ultimately rely on reports filed with the Energy Information Administration (EIA). It is fairly clear that it took some time for EIA to take full and appropriate account of the impacts of retail competition on the price data reported to them. To the extent

Table 10. Industrial Price Equations 1981-2003 (standard errors in parenthesis)

Variable	GLS	Fixed-effects	Fixed-effects plus time trend
RFC	0.53	0.48	0.23
	(0.03)	(0.031)	(0.026)
HYDRO	-0.40	-0.29	-0.62
	(0.10)	(0.15)	(0.12)
NUCLEAR	0.11	0.056	0.029
	(0.071)	(0.075)	(0.057)
YIELD	0.078	0.079	0.029
	(0.0045)	(0.004)	(0.004)
SIZE	-0.4	-0.4	-0.3
	(0.04)	(0.04)	(0.03)
PURPA	0.24	0.10	0.18
	(0.09)	(0.09)	(0.072)
EWG	-0.24	-0.23	-0.15
	(0.054)	(0.055)	(0.042)
RETAIL	-0.18	-0.20	-0.043
	(0.039)	(0.039)	(0.03)
R^2 (corrected)	0.61	0.68	0.82

Source: See text and appendix

that customers served by competitive retailers were excluded from the reports filed with EIA, the price data overestimate the actual prices realized by those customers who switched. To the extent that utility reports include only the delivery charges for customers who have switched, average prices may be underestimated. Second, several of the right hand side variables are not exogenous (though they change slowly). We know, for example, that retail competition was introduced in states with the highest retail prices and, other things equal, this would lead to an underestimate of the effect of retail competition. The long time series and the use of state-specific fixed effects should help to mitigate these problems, but not necessarily fully. Thus, further analysis to develop a more complete structural framework and relying on better data would be desirable.

6. CONCLUSION

The transition to competitive electricity markets has been a difficult process in the United States. In 1997 I wrote "[E]lectricity restructuring ... is likely to involve both costs and benefits. If the restructuring is done right...the benefits ... can significantly outweigh the costs. But the jury is still out on whether policymakers have the will to implement the necessary reforms effectively" (Joskow (1997), p. 136). I believe that statement continues to be true today. Creating competitive wholesale markets that function well is a significant technical challenge and requires significant changes in industry structure and supporting institutional and regulatory governance arrangements. It requires a commitment by policymakers to do what is necessary to make it work. That commitment has been lacking in the U.S. The major barrier to a successful restructuring and competition program in the U.S. at the present time is political. Many of the technical problems associated with creating well functioning competitive electricity markets have been solved, often through bitter experience. While FERC has been a leader in promoting competitive markets, the Bush administration and the Congress have provided tepid support at best. Political compromises over restructuring, conflicts between federal and state regulations, the mixing of states with and without competition programs, the absence of a strong pro-competition policy and associated statutory authorities coming from the Congress and advanced by the President have all worked to make successful reforms extremely difficult.

Despite these difficulties, considerable progress has been made and many useful lessons have been learned. There is growing evidence that competition can lead to cost and price reductions if policymakers will support the regulatory and institutional changes needed to allow competitive market forces to work. However, the creation of competitive market forces has also encountered some significant and costly problems and it is important that future policies reflect the lessons learned from this experience. My interim assessment is that the glass is half full rather than half empty at the present time. I take this view based on the evidence of performance improvements and because the revisionist history about the "good old days of regulation" has conveniently ignored the $5000/Mw nuclear power plants, the 12 cent/kWh PURPA contracts, the wide variations across utilities in the construction costs and performance of their fossil plants, and the cross-subsidies buried in regulated tariffs that characterized the regulatory regimes in many states. As we look at the costs and benefits of competition we should not forget the many costly problems that arose under regulation.

Looking at the maps in Figure 1 and Figure 3 it seems clear that about half of the country is focused on moving forward with pro-competition policies, at least at the wholesale level, and half is not. Going forward I suspect that we will see a sort of contest between the performance of the regulated monopoly framework and the competitive market framework for governing the electric power sector in the U.S. With continuing analysis of comparative performance of alternative institutional arrangements we will be able to determine more definitively what is the best that we can do in an imperfect world.

DATA APPENDIX

State-level data from 1970 through 2003 were used to estimate the regression coefficients for equation (1) as reported in Tables 7, 8, 9 and 10. Maryland and the District of Columbia have been combined for all years due to the sources' combined data presentation in several years. Idaho was dropped due to data imperfections. Data construction becomes challenging after 1997 as a result of divestiture of utility plants, entry of EWGs and spread of retail competition. EIAa, EIAb, EIAc are used extensively to fill gaps in EEIa and EEIb.

Retail electricity prices: Retail prices are measured as average revenue per kWh sold to residential and industrial customers respectively for total electric power industry by state. These data include municipal and cooperative distribution companies. EEIa, EIAa, EIAb, EIA (2005).

Average fuel cost (adjusted for changes in CPI with 1970 = 1): Average real fuel cost per kWh of electricity generated in each state, including by independent power producers after 1997. EEIa, EIAa, and EIA (2005).

Hydro electric generation share: Fraction of total electricity generated in each state accounted for by hydroelectric generating capacity. EEIa and EIA (2005).

Nuclear generation share: Fraction of total electricity generated in each state accounted for by nuclear generating plants. EEIa and EIA (2005).

PURPA generation share: Estimate of fraction of total electricity generated in each state accounted for by PURPA Qualified Facilities. Series starts in 1986. MWh of PURPA generation assumed constant after 1997. EEIb and EIA (2005). Overlap years are averaged.

EWG generation share: Estimate of fraction of generation in each state accounted for by unregulated generators, excluding PURPA generators. Series starts in 1998. EIA (2005).

Real bond yields: Moody's average yield on electric utility bonds minus the annual rate of inflation in consumer prices (CPI).

Average residential and industrial kWh consumption per customer: Average consumption per retail customer for residential and industrial customers for the total electric power industry by state. EEIa, EIAa, EIAb, EIA (2005).

Retail competition: Dummy variable = 1 if retail competition. Author's assessments based on programs initiated in each state. First retail competition program 1998. California is treated as having retail competition beginning in 1998.

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Restructuring the U.S. Electric Power Sector: A Review of Recent Studies

John Kwoka

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Abstract The restructuring of the U.S. electric power industry has been described as "one of the largest single industrial reorganizations in the history of the world." As with deregulation and reform of other industries, electricity restructuring was intended to produce cost efficiencies and price benefits to consumers. Whether it has achieved its stated objective is the focus of a number of recent studies that are examined in this review. The studies differ in numerous important ways – most importantly, in their methodologies and their conclusions. The focus of this review is on the strengths and limitations of their specific methodologies and, hence, on the confidence one might place in their conclusions. The article begins by setting out the basic methodological approaches employed in public policy evaluation. It then illustrates these points with examples from methodologies employed in several studies of electricity restructuring, concluding that several methodological deficiencies call into question the study results. In particular, despite much advocacy, there is little reliable and convincing evidence that consumers are better off as a result of the restructuring of the U.S. electric power industry.

Keywords Electricity · Restructuring · Deregulation · Evaluation studies

1 Introduction

For most of its history the U.S. electricity sector has been dominated by large, vertically integrated, and heavily regulated utilities. The natural monopoly characteristics of the industry, its enormous economic importance, plus concerns about corporate abuses and mergers led to state and federal regulation of investor-owned utilities and also to

J. Kwoka (✉)
Department of Economics, Northeastern University, 301 Lake Hall, Boston, MA 02115, USA
e-mail: j.kwoka@neu.edu

public ownership throughout much of the 20th century. Beginning in 1978, however, reforms made inroads on this traditional structure and operation of the private sector of this industry. By the late 1990s a transformed industry had started to take shape, characterized by substantial de-integration, significantly looser regulation, and more market-oriented operation.

These changes were intended to bring competition to wholesale and retail customers of electric power. Competition among independent generators was supposed to create a level playing field for wholesale power transactions so that retail customers and local distribution utilities could shop for power from a wide range of alternative suppliers. The result was supposed to be lower wholesale costs and thus lower retail prices. By the year 2000, about half the states either had restructured their electricity sectors or were planning to do so. In many places the transmission grid was operated by regional transmission organizations that were relatively free of artificial constraints. While the problems in California and elsewhere brought further restructuring to a halt, many states were irreversibly committed to deregulation and, in any event, reforms at the federal level continued. The result is that electricity restructuring is substantially complete in some regions of the country, although other regions are much less affected.

Because the changes to electricity markets have varied both over time and by state or region, it is possible to compare costs and/or prices between states that have restructured and those that have not, or between pre-restructuring years and the post-restructuring period. Such comparisons would permit an economic assessment of the actual impact of reforms and determine whether expectations about cost and price effects are being met. Over the past five years a number of such studies have been undertaken. This review discusses ten of the major quantitative studies,[1] focusing on their methodological soundness and hence on the reliability of their conclusions.

These ten studies differ considerably in their conclusions as well as in their methodologies. Eight offer essentially favorable assessments of electricity restructuring, three of those with substantial qualifications. The other two studies reach negative conclusions. Any ultimate assessment of restructuring, of course, does not depend on how many studies come to each conclusion, but rather which of them is convincing as a result of using sound methodology.

To that end, this review begins with a discussion of various methodologies that are commonly used in economic evaluations of policies like restructuring or deregulation. That is followed by an analysis of three significant methodological deficiencies that characterize many of these studies. The individual studies are then assessed to illustrate major methodological issues. The final substantive section raises some additional effects of electricity restructuring that are relevant to a comprehensive assessment but are either not addressed or receive inadequate attention in these studies.

[1] Even as this article was being finalized, other studies appeared. These include: *A Review of Electricity Restructuring in New England*, commissioned by the New England Energy Alliance and authored by Polestar Communications, and *A Cost-Benefit Assessment of Wholesale Electricity Restructuring and Competition in New England*, commissioned by "a US electricity generating company" and authored by M. Barmack, E. Kahn, and S. Tierney of The Analysis Group. In addition, some qualitative studies have come out, but these are not covered in this review. For commentary on the latter, see http://www.appanet.org/files/PDFs/RestructuringStudyKwoka1.pdf.

2 Assessing Deregulation: Procedures and Pitfalls

Economics is routinely used to perform assessments of the effects of regulation or deregulation of various industries. Here we review standard methodologies for conducting such studies, highlighting the strengths and limitations of each. We then discuss three major methodological problems shared by most of the studies being evaluated.

2.1 Empirical Methodologies

The economics literature recognizes four major approaches to assessing the performance effects of regulation and deregulation.[2] The first and perhaps most obvious approach is a direct comparison of regulated and unregulated firms and markets. Such studies can be either cross-sectional–for example, across states with and without regulation–or time-series, say, during a period when regulation begins or ends. In either case, attention must be paid to (1) what constitutes the regulatory difference or change that arguably affects performance, (2) the exact date of change in regulation or deregulation, (3) any non-policy factors that need to be controlled for, and (4) the possibility that those states that choose to deregulate differ in some way that alters the effects of the policy.

The second approach is to examine the effects of variations in the intensity of regulation across time and place. This approach is particularly well suited to the circumstance where complete deregulation may not have occurred but regulation varies in its stringency across firms or markets. In this case with proper modeling and attention to all of the above considerations, one can measure the effects of the degree of change or the difference in regulation that is observed. It may even be possible to project the effects of full deregulation based on the partial effects that have occurred.

Third, where actual data are unavailable, inadequate, or otherwise compromised, a controlled experiment is a possible means of predicting the effects of deregulation. Such an experiment in principle might be a field experiment or a laboratory experiment. Confidence in the results of a laboratory experiment may be tempered by the complexity of the regulation examined, the sophistication of the experimental design, and the ability to capture other factors that may be relevant to the outcome of regulation.

Fourth and lastly, one might estimate an industry model based on underlying demand, costs, and other relevant behavioral relationships. A well-specified and well-estimated econometric model may provide the basis for predicting the effects of deregulation; but of course it is dependent on the availability of good data, correct model specification, and the resolution of any econometric issues. Alternatively, simulation of a well-specified model with correct parameters is an accepted, although less commonly employed, approach to measuring likely regulatory effects. The studies reviewed illustrate all of these approaches except for controlled experimentation.[3]

[2] This discussion borrows heavily from Joskow and Rose (1989).

[3] Controlled experiments have been used in electricity markets in other contexts, however, such as pilot programs and test cases for time-of-use pricing.

2.2 Pitfall #1: Defining Electricity Restructuring

We begin with the most basic of problems–the lack of precision in what is meant by "restructuring." The studies reviewed here vary enormously in their definition of the reforms that they study, and indeed some do not offer a specific definition at all. But absent a clear and consistent meaning of restructuring, its effects will not be isolated and measured consistently.

One reason for such variation and ambiguity is that, in contrast to industries such as airlines and perhaps telecom, electricity restructuring was not a single event that occurred at one point in time. It was the cumulative result of several quite different policy actions taken over a considerable period of time. Moreover, some of the policies did not trigger sudden change but rather phased in the changes, or allowed them to occur, over an extended interval. These factors make "restructuring" a rather complex phenomenon to study.

The studies reviewed here deal with this multiplicity of reform events and the lack of precise timing in a variety of ways, some more satisfactorily than others. Some acknowledge the multiple dimensions of reform, creating separate variables for the major policy actions and even using continuous variables to capture the progressive nature of the consequences of certain actions. Others, however, treat restructuring as if it consisted of a single event that occurred at one point in time. Often in such studies a single year is chosen to represent deregulation in its entirety. This approach fails to capture the actual effects of restructuring by incorrectly characterizing its multi-faceted and time-dependent nature. Portraying restructuring as a dichotomous event may result in the failure to detect a true effect of restructuring, or seeming to find one where none exists.

Clearly, therefore, these studies interpret restructuring or deregulation in a variety of quite different ways. The most satisfactory of these explicitly recognize and measure the several dimensions and phased timing of policies that constitute "restructuring" in this industry. Much less satisfactory, sometimes to the point of distorting events, are studies that treat the process as if it were a single event occurring at one point in time.

2.3 Pitfall #2: Post-Reform Price

The second major pitfall in electricity reform studies concerns the prices used for comparison.[4] In assessments of deregulation or regulatory reform in most industries, the post-reform price is obvious, and the challenge is to identify the comparable pre-reform price. In the case of electricity, however, the post-reform price is itself often distorted, so that comparisons to it are invalid as guides to the effects of restructuring. There are three reasons why post-reform prices may not be correct measures:

[4] Several of the studies examine other outcome measures besides price or cost, for example, generator heat rates or market liquidity. We do not focus on them in this report since, if these represent important actual performance improvements, they should ultimately manifest themselves in cost or price benefits. Indeed, it would be double counting to measure both the source of efficiency gain and its direct cost effect. In addition, the promise of restructuring was that costs and prices would show improvement. For these reasons we focus on price and cost effects.

rate reductions and freezes, stranded costs, and excess capacity. Each of these merits discussion.

2.3.1 Rate Reductions and Freezes

As previously noted, several New England states and California initiated state-level restructuring in 1998, with many more states following over the next several years. Restructuring typically involved several distinct elements, notably, divestiture of generation assets, provision for stranded cost recovery, and initial rate reductions followed by freezes. By 2003 some 64 rate reduction and freeze plans were in effect in nearly half the states (Rose and Bujimalla 2002). Initial rate reductions ranged from 3 to 20 percent, ensuring immediate gains to consumers. Freezes extended from two to ten years, during which time consumers would be guaranteed little or no price change regardless of utilities' underlying costs. If costs fell as expected, unchanged retail price could at least be expected to generate excess funds to help pay utilities for their stranded costs.

In fact, costs unexpectedly rose as natural gas prices spiked in 2000-01 and wholesale auction prices for electricity rose. This forced utilities and their regulators to deal with frozen retail rates that in many cases no longer covered utility costs. Many state utility commissions responded by allowing utilities to book as "deferred balances" those costs that exceeded revenues from the frozen rates. These deferred balances, which often grew to be quite substantial, could then be charged to ratepayers as soon as the rate freeze expired. The effect of this arrangement was to keep retail prices below their equilibrium level temporarily, but after expiration of the freeze, those prices would jump substantially in a "catch-up" phase.

Substantial price increases have occurred in a number of utilities' service territories immediately upon expiration of their rate freezes. The most striking and controversial cases involve Connecticut Light and Power, Pike County Light and Power in Pennsylvania, and Baltimore Gas and Electric, which filed for rate increases in excess of 70 percent upon expiration of the freezes.[5] These sudden rate hikes make clear that the earlier period frozen prices were an administrative arrangement–perhaps even a simple postponement of changes–rather than equilibrium prices.[6]

Despite the fact that observed post-reform prices in states with freezes were divorced from underlying costs and hence not reliable guides to market equilibrium, several studies use price in just that way and without qualification. Their methodologies are therefore invalid. Other studies note the existence and influence of rate freezes, but proceed nonetheless to perform calculations that make no adjustment for them. Those studies are incomplete and their conclusions subject to revision. A different strategy employed in one case is to use industrial rather than residential rates in the belief

[5] As this is written, state regulatory commissions have modified these requests by allowing smaller rate increases over more years as an equivalent method of cost recovery. Electricity consumers in Illinois have recently been informed of rate increases ranging from 22 to 55 percent in January 2007. "Energy Auction in Illinois Will Lead to Jump in Rates for Consumers," *The Wall Street Journal*, Sept. 18, 2006, p. A8.

[6] It may be possible to infer what rates would likely have been in the absence of the freeze by smoothing the price path during the years of the freeze together with the post-freeze catch-up years. The annual rate of change across all those years might approximate the counterfactual price for comparison purposes.

that rate reductions and freezes were directed at residential users. That argument is incorrect, however, as industrial rates have been subject to rate reductions and freezes in perhaps half the cases. While those have often not been of the same magnitude or duration, reliance on industrial rates as reflecting equilibrium is misplaced.

2.3.2 Stranded Costs

Stranded costs refer to sunk costs and other committed expenditures that the utilities were unlikely to recover in a competitive generation market. Most of these costs arose from three sources: (1) the difference between market value and book value of generation plant in a competitive environment; (2) the excess costs of long-term contracts to purchase cogenerated power mandated by the Public Utilities Regulatory Policy Act of 1978 (PURPA), and (3) the costs of non-completion and eventual decommissioning of nuclear plants.

As noted, rate freezes in many states were accompanied by provisions for recovery of stranded costs. The recovery process typically involved three steps. First, the utility and the state regulatory commission had to agree on the amount of such stranded costs.[7] Second, funds in that amount were transferred to the utility and the costs "securitized" or paid for by the state with bonds of eight to 15 years duration.[8] Third, the annual costs of the bonds were treated as a business expense of utility operation, so ratepayers would pay them off fully over that time horizon.

One method of raising the necessary revenues for bond payment was supposed to be the difference between the frozen rates and expected declining unit per kilowatt-hour costs of the utilities under deregulation. This difference–the so-called competitive transition charge (CTC)-would be collected from ratepayers and accumulate during the freeze period, compensate utilities for their stranded costs, and then expire. At that point, rates were expected to fall to a level reflecting underlying costs of operation since the CTC would no longer be incorporated into the rate level.

The implication of this scenario is that when the CTC was in effect, actual rates were higher than equilibrium, since they included an administratively set surcharge having nothing to do with utility operating costs. Comparisons of pre-reform and such post-reform prices are therefore invalid because as they fail to recognize that observed post-reform prices are overstatements of equilibrium prices and hence that comparison with pre-reform prices understate the difference. Nonetheless, most of the studies evaluated here fail to correct for the distorting effects of stranded cost recovery charges. Two studies do attempt adjustments, not entirely successfully, and three others acknowledge this issue.

2.3.3 Excess Capacity

The period from 2000 to 2004 has been characterized as one of substantial excess generating capacity in many regions of the country. The U.S. Federal Energy

[7] Both the principles and the amounts of stranded cost recovery were heavily debated. For discussion, see Joskow (2000).

[8] For a discussion of securitization and related matter concerning stranded costs, see Brennan et al. (2002).

Regulatory Commission's (FERC) *State of the Markets Report* for 2005 noted that more generation capacity was built during that time than in any other five-year period in history–indeed, nearly as much as in the previous 20 years.[9] While loads increased somewhat, this capacity growth put pressure on operations, suppliers, and prices. Many combined-cycle plants have run considerably less than anticipated, often as intermediate rather than baseload. In addition, they have tended to compete with each other rather than with less efficient older plants. Moreover, much of the additional plant has been built in the Southeast; the Pennsylvania-New Jersey-Maryland Interconnection (PJM); and the Southwest, which are all regions already with surplus capacity.

The consequences have been rising capacity margins (that is, generator capacity in excess of peak utilization), abnormally low prices, and generator bankruptcies. Relative to normal capacity margins of 15-18 percent, nine of the 10 regions in the North American Electric Reliability Council (NERC) experienced excess summer reserve margins in 2004, in some cases twice the normal levels.[10] As FERC noted, this put "downward pressure on both energy and capacity prices in the market, and reducing net revenues for gas-fired capacity in most regions."[11]

The implications of excess capacity for a study of the price effects of restructuring are straightforward: To the extent that post-reform prices were depressed by the overhang of excess capacity, those prices do not represent a reliable basis for assessing the effects of reforms themselves. Rather, they embody a temporary mismatch of supply and demand that has the effect of lowering post-reform price below its equilibrium value and thus overstating the long-run effects of reform itself. While a few of the surveyed studies acknowledge the existence of excess capacity, only one makes an explicit effort to adjust post-reform price for market disequilibrium, although that study's procedure is neither described nor seemingly effective. To that extent, most of these studies overstate the effects of reform itself.

2.4 Pitfall #3: Causation

The third methodological issue concerns the determination of causation, that is, whether or not reforms are actually responsible for some observed and properly measured change in price or cost. This is, of course, the ultimate purpose of studies evaluating electricity reforms, but a convincing demonstration of causation requires attention to several issues, not all of which are correctly addressed in these studies. These issues are: controlling for other factors, projection and prediction, and selection bias and endogeneity. We discuss each in turn.

2.4.1 Controls for Other Factors

As noted at the outset, economics rarely employs controlled experiments. Rather, relationships of interest must be isolated from real world data that are affected by

[9] FERC, State of the Markets Report 2005, pp. 28–30, 59.

[10] FERC, ibid, Table 6.

[11] FERC, ibid, p. 29.

a range of other factors. Controlling for those other influences is essential to actual determination of causation. Otherwise, in the common phraseology, correlation may be misinterpreted as causation. In the present case this raises a concern that restructuring may be judged responsible for some outcome whereas other factors are ultimately responsible. To establish causation correctly, one must control for those other factors in some fashion. There are several standard techniques for doing so depending on the underlying approach of a study as well as on the availability of data.

Clearly, the ideal technique would be to identify and measure all other relevant factors and to include them in some regression model. Regression analysis is well designed for this purpose: to isolate the incremental effect of individual causal factors on some outcome variable. Thus, one might run a regression of prices in different states on a variable for whether or not each state has restructured its electricity industry, plus variables for other possible influences on state electricity price. The latter might include local differences in generation type, or climate, or fuel costs. In principle, the resulting cross-sectional data might disclose the separate effect of restructuring.

The problem is that not all possible causal factors can be identified, or at least one cannot be sure to have done so. Moreover, any conceptual variable may or may not be measurable, or may have alternative measures with different characteristics. The result is that the model still may not have controlled sufficiently for other relevant factors. Two common approaches to this problem are as follows:

Panel data can be used. The addition of time series means that any unmeasured or immeasurable factors that affect each particular observation (say, a state) can easily be controlled for by using fixed effects terms on those observations. The fixed effects terms hold constant those factors that are specific to the state and that do not change over time, allowing the regression to focus on those factors–like restructuring–that vary across states or over time.

The so-called difference-in-differences approach entails a comparison, say, of the price difference before and after restructuring in those states that did restructure, with the price difference over the same period in states that did not. Any unmeasured influences on all states' prices during this period (e.g., general fuel price increases) would be captured in the price difference in non-restructured states. By subtracting that difference from the price difference in states that restructured (but also experienced the fuel price change) one can in principle isolate the effect of restructuring.

Variations on these methods are possible. For example, one might use only time series data rather than full panel data, or one might identify a comparison group rather than all non-restructured states. These are inferior to the more general approaches just mentioned, but may be better than uncontrolled comparisons. Of course, poorly chosen comparison groups – for example, a small number of non-restructuring states with unusual characteristics themselves – are unreliable guides to the effects of policy.

The studies evaluated in this report vary in the adequacy of their controls. Some have a lengthy list of control variables in their econometric models, whereas others have few (in one case, seemingly only one) control variable. Three of the econometric studies used panel data. In certain comparative studies, control groups are chosen with little or no explanation. Some of these techniques seem not to exercise adequate care.

2.4.2 *Projection and Prediction*

Studies that employ an econometric model to predict the counterfactual (no-restructuring) price use the data in two fundamentally different ways. This is best understood by example: Some base their model on all years of data, including control variables plus a dummy variable for the period of restructuring.[12] The coefficient on the dummy variable will in principle isolate the effect of policy on price, taking into account the effects of fuel costs and other control factors. An alternative approach is to estimate the same model of price on fuel costs and the other control factors, but only on data for the pre-restructuring years. The resulting coefficient estimates can be used to predict counterfactual prices in the post-restructuring period based on actual fuel costs and the other factors. That is, the coefficient on fuel price estimated from the pre-restructuring period is multiplied by actual fuel price in later years to project later electricity prices, and similarly for the other factors. The validity of this approach depends on the assumption that the same forces, other than policy, would otherwise have determined electricity price in the same way in the post-restructuring period.

There are two reasons why this approach is inferior to the first approach based on the full sample of data. First, using the entire sample gives more data points on which to estimate the effect of fuel costs and the other factors. This strengthens the overall predictive power of the regression model. Second, failure to use the entire period will result in erroneous predictions of the restructuring when the relationship between price and the non-policy variables differs in the post-restructuring period vs. the pre-restructuring period. If, for example, fuel costs reach levels never before encountered, levels that may prompt conservation measures or changes in generation technology that alters the relationship between fuel costs and price from what was estimated in the pre-restructuring period. Hence, the previously estimated relationship will incorrectly predict post-restructuring price.

For these reasons, econometric techniques and counterfactual price calculations based on full samples (so-called "within sample" prediction) are preferred to "out-of-sample" estimates. Among the econometric studies reviewed here, only two utilize within sample methods.

2.4.3 *Selection Bias and Endogeneity*

Econometric models or even simple comparisons of prices in restructuring versus non-restructuring states can encounter another more subtle methodological problem of causation. In principle in such models, the fact that some states have restructured is interpreted as the cause of any observed price difference between them and non-restructuring states, after controlling for all other relevant factors. But it is also possible that restructuring occurred in those particular states precisely because of the prices that existed there prior to restructuring, or because of some common force that simultaneously caused high prices and an inclination to restructure. To that extent

[12] For simplicity of this discussion only, we assume a discrete point in time for restructuring, so that a dummy variable captures policy. As just discussed, most reforms in electricity cannot be represented adequately in this manner.

the restructuring states may not be a random sample of all states, as econometric modeling requires. In that case, the result may be a biased estimate of the price effect of restructuring since the estimate derives from a select set of states. The result illustrates the problem of "selection bias" or "endogeneity."[13]

In concrete terms, suppose that restructuring states are those that previously had unusually high prices. Restructuring may therefore have occurred in those very states since policymakers there were especially eager to try restructuring as a method for reducing prices. But in that case it is the fact of high prices in the first place that makes the state a restructuring state, and hence the measured effect of restructuring on prices after restructuring does not have the usual interpretation. The estimate at best might measure the effect of restructuring for high-price states. At worst, it may be entirely suspect if some characteristic of those states' political, social, or economic make-up simultaneously causes both the high prices and its effort to restructure.

Not all models assessing policy effects necessarily encounter selection bias. Rather, there must be a true and significant causal connection between some characteristic of the selected group and the policy variable. There are statistical tests for selection bias and endogeneity as well as corrections for them, and while the latter may be complicated, good methodology requires recognition of and attention to the issue. Implicitly assuming that restructuring "just happens" in some places, by contrast, may produce estimated effects that are either larger or smaller than the true effect. Among the studies reviewed here, a few acknowledge the issue, and one makes some effort to deal with it, but most fail to address it at all.

2.5 Concluding Observations on Methodology

The studies reviewed in this report illustrate the wide variety of standard methodological approaches to evaluating regulatory reforms. Unfortunately, they also illustrate a number of pitfalls in such methodologies. Three of the more common ones discussed here are the failure to be precise about the reforms being evaluated, the use of a post-reform comparison price that is itself distorted, and an inadequate specification of causation. As we shall see, these problems, as well as others specific to each study, cast doubt on the conclusions reached by these various studies.

3 Five Econometric Studies of Price

Five of the ten studies reviewed in this report offer quantitative assessments of the effects of restructuring that derive from econometric models of retail electricity prices. The models are used to examine whether prices differ between states or utilities that restructured versus those that did not, or whether prices after restructuring differed

[13] The term endogeneity reflects the fact that the probability of being in the sample is related to a variable of interest, in this case price itself. To be clear, the problem is not simply that the restructuring states have some different characteristic. That would constitute an "omitted variables" issue, but not necessarily bias the coefficient on the policy action. Selection bias arises from the fact that "the unmeasured variable affects both the dependent variable and the probability of being in the sample" (Kennedy 2003, p. 286).

from those that would otherwise have prevailed. Most studies combine both types of data into panel data sets in order to strengthen the statistical basis for their conclusions. We discuss these studies in order of their publication, summarizing and evaluating each.

3.1 Cambridge Energy Research Associates Study (2005)

The 2005 Cambridge Energy Research Associates report attempts to measure the effects of electricity deregulation on the trend of power prices. The procedure for determining the effects of deregulation (using 1997 as the break point) involves estimating what the price would have been with continued regulation for the period 1998-2004 and comparing it to the actual "deregulated" price during that period.

The study develops an econometric model to establish the relationship between fuel and financing costs and electricity price under regulation. This model is estimated using data for the Northeast, West, South, and Midwest from 1981 to 1997. Comparing actual rates for 1998-2004 to predicted rates based on the model leads to the conclusion that residential electric customers paid about $34 billion less for the electricity during this period than they would have if traditional regulation had continued.[14]

The CERA study uses one of the basic methodologies outlined in the previous section: an econometric model of price that allows for controlled comparison of regulated versus unregulated prices over time. For this approach to yield sound results, the mechanism for predicting counterfactual price (the regulated price in unregulated years) must be sound. In this regard, despite one or two strengths, the CERA study generally falls short, for a number of reasons.[15]

Perhaps most basically, the study's use of 1997 as the year of "demarcation" between regulation and restructuring is too simplistic since there is no single point in time for deregulation. Second, the model explaining price is fairly rudimentary, relying on only two explanatory variables–fuel price and rate base cost—while overlooking other factors such as generation type and demand conditions. Given the panel data set employed, the model should also include fixed effects for regions and years to control for other influences.

Third, the study uses a model estimated for 1990-97 to predict 1998-2004 prices. Such "out-of-sample" prediction is statistically inferior to estimating a model on the entire period and then testing for differences in the period of deregulation. As a result, the CERA model predicts rather poorly. For example, the predicted price exceeds actual price in the year 1997 for all regions, and in three regions for the year 1996. These "effects" seem to have preceded their "cause," casting doubt on the model. Fourth, the study concludes that the South has the largest savings–$24 billion of the total net benefit of $34 billion–when that region has experienced the least restructuring. Finally, the study acknowledges both rate freezes and excess capacity as issues, but (for reasons discussed in the previous section) erroneously interprets those as benefits of restructuring.

[14] CERA Study, pp. ES-1, I-1.

[15] This discussion draws on some points made in Christensen Associates (November 2005) and Spinner (2005).

3.2 Joskow Study (2006)

In the last section of the article *Markets for Power in the United States: An Interim Assessment* on electricity deregulation, Joskow offers an analysis of retail prices after reform. He notes the difficulties of determining the counterfactual price and then proceeds with three approaches to the problem: an analysis of time series data on prices, a comparison of price trends in states with and without retail competition, and a regression analysis. The following discussion focuses on the last of the three approaches.

Joskow (2006, p. 28) offers a "first, admittedly crude empirical analysis" of the effect of deregulation on retail residential and industrial prices. He estimates an equation explaining average residential or industrial price by state for the period 1970-2003, as a function of variables measuring a combination of cost drivers and policy initiatives. The regression model is run separately for residential rates and industrial rates and also for the shorter period 1981-2003 during which rates seemed to resume their long-term decline.

In all four models the cost drivers behave as would be expected. For policy variables, Joskow reports that for the longer time series, PURPA generation is associated with higher retail prices resulting from locking utilities into costly power. On the other hand, the results confirm that the greater the share of electric sales from exempt wholesale generators, the lower the retail prices. States implementing retail competition have had lower retail prices, everything else held constant. Estimates for 1981-2003 reflect a somewhat lesser statistical significance to most variables in the recent period. Overall, Joskow concludes that both wholesale and retail competition lead to lower retail prices–perhaps 5 to 10 percent lower on average, holding cost factors constant. These results are similar for both residential and industrial prices in both time periods. Overall, this study finds significant benefits to restructuring.

Joskow's study is one of the more careful quantitative assessments of electricity restructuring. He uses the full sample in order to maximize reliability of coefficient estimates, incorporates a number of control factors which prove significant, and controls for both state-specific and time-specific errors. Joskow acknowledges a number of caveats to his results, including data availability problems associated with customers served by competitive retailers. He also recognizes the endogeneity of some right hand side variables such as the presence of retail restructuring, which likely leads to an underestimated effect of retail competition. Finally, Joskow (2006, p. 32) states that the effect of retail competition on consumers is not consistently positive in all states.

Apart from these qualifications, additional questions can be raised about the analysis. First, there appears to be no correction for price reductions and freezes in the deregulation period. As previously discussed, leaving these effects uncorrected will overestimate of the effects of restructuring on price. An analogous concern arises with respect to the impact of excess capacity, which also appears to have temporarily held price down, and stranded cost recovery, which works in the opposite direction. The problems result in an inappropriate comparison of regulated price to distorted deregulated price.

Second, retail restructuring enters as a zero-one dummy variable, meaning that it is assigned a value of zero in the absence of restructuring or a value of one where restructuring is deemed to have occurred. But electricity retail restructuring is in reality a continuous process of increasing competition in state retail power markets, and simply allowing customers to choose another electricity supplier does not mean that there is competition.

3.3 Taber, Chapman, and Mount Study (2006)

The working paper *Examining the Effects of Deregulation on Retail Electricity Prices*, notes that the purpose of electricity deregulation was to reduce the retail price of electricity. This empirical study compares prices for utilities in deregulated states with prices in regulated states between 1990 and 2003. It defines deregulation in the context of wholesale markets in any of three different ways: A utility is said to be deregulated (1) if it belonged to an independent system operator (ISO) with an auction-based market in the year 2002; (2) only for those years in which it actually belonged to an ISO; or (3) only for the years it belonged to an ISO that had an auction-based market."[16]

Prices are examined for each of four consumer classes (residential, commercial, industrial consumers, plus the average overall prices) and also for three categories of utilities: privately owned in regulated states, privately owned in deregulated states, and publicly owned. Prices are examined both in nominal and in real terms. With all possible combinations of consumer classes, nominal/real prices, and definitions of deregulation, there are 24 different possible model specifications. Taber et al. suggest a number of factors that can independently affect prices of electricity and must therefore be controlled for, including fuel cost per unit of output, heating and cooling degree days, and type of generation. The policy variable is simply whether or not a utility belongs to an ISO with an auction-based wholesale market for one or more of the years in the period.

The Taber et al. study introduces a number of different model specifications. In addition to having simply price as the dependent variable, another set of regressions uses "gap variables" as the dependent variable, where "gaps" are the percent difference between regulated and unregulated price, and between public and private utility prices. Each model is estimated on all 24 combinations of consumer classes, deregulation definitions, and nominal/real prices, resulting in more than a hundred different regressions. The authors observe that for most ISOs the average coefficient values are both positive and larger than the coefficients for privately regulated utilities. Hence, the results "do not support a conclusion that in aggregate deregulation has lowered electricity rates relative to those rates in still-regulated states."[17]

The Taber et al. study is notable for its multiplicity of model variants, but it has a number of limitations. First, the basic definition of a deregulated utility–membership in an auction-based ISO in 2002–overlooks two of the key components of restructuring: retail choice and divestiture. The approach treats restructuring as a dichotomous event,

[16] Somewhat different second and third definitions are given later in the study.

[17] Taber et al. (2006, p. 29). The authors concede that 39 out of 60 coefficients from which the averages are generated are significant at the 5% level.

although most aspects involved a process of phasing in. Second, the rationale for using "gap variables," or percent changes, is unclear. The economic factors that are responsible for different price levels are not the same as those responsible for changes, and, indeed, it is unclear whether deregulation should alter the rate of change in prices as opposed simply to altering their level. It may therefore not be surprising that the regressions on "gap variables" lead the authors to conclude that price differences are not easily explained by any of the models (Taber et al. 2006, p. 27).

Third, in addition to deregulated utilities, the study incorporates prices of privately owned regulated utilities, since they are the obvious comparison group. But it also includes publicly owned utilities, and then specifies the model so that they are the default group. Under that approach, a negative coefficient on an ISO term would simply indicate less expensive power from that ISO member relative to publicly owned systems, not that deregulation was effective in reducing retail rates. Fourth, the "meta-summaries"–or arithmetic averages of the coefficients from dozens of regressions–offered in the study do not represent a valid basis for drawing conclusions. There is no economic meaning or statistical test for the "average value" of a coefficient from a group of entirely separate regressions. Finally, the Taber et al. study does not recognize that the post-restructuring price reflects price reductions and freezes, stranded cost recovery charges, and excess capacity for many utilities.

3.4 Fagan Study (2006)

The study *Measuring and Explaining Electricity Price Changes in Restructured States*, focuses on industrial prices. Fagan develops a counterfactual model of price differences between restructuring and non-restructuring states over the period 2001-2003. Counterfactual prices are determined by first constructing a model that attempts to explain prices for the period 1990-97 using selected state-specific inputs (e.g., fuel price and time trend), and then applying that model to predict prices based on values of the same inputs for 2001-03.

Results indicate that the "vast majority of [high] explanatory power lies with the time variable" and that "the gas variable is rarely significant in the state models" (Fagan 2006, p. 38). Using these regressions and data for 2001-03 on the explanatory variables, predicted prices (as if regulation persisted) are obtained for restructuring utilities. The predicted price series is then compared to actual prices in 2001-03, resulting in actual prices lower than predicted in 12 of 18 restructured states but in only seven of 25 non-restructured states.[18]

Fagan then undertakes a separate comparison of average price differences between all restructuring and all non-restructuring states based on "consumption-weighted average prices" in 2001-03. He reports that the average actual prices were 7.5 percent higher than predicted prices in restructuring states, compared to 9.2 percent higher in non-restructuring states. When price data in restructuring states are adjusted for stranded costs, the result is that actual prices in restructuring states are only 1.3 percent higher than predicted.

[18] A mean difference test is said to yield a t-statistic of 2.07, just barely in the range of statistical significance.

Finally, the Fagan study then develops two additional models to examine further the determinants of the differential between actual prices and predicted prices. The first simply tests for a correlation between the price difference from the previously predicted values and a restructuring variable. The second model examines the change in price for each state between 1993-95 and 2001-03, using a number of explanatory variables. Fagan concludes from these regressions that "neither regulatory reform at the retail level (restructuring status), nor at the wholesale level (RTO participation) is a significant driver of the restructured states' superior price performance" (Fagan 2006, p. 41).

The Fagan study contains a number of specific limitations. First, the counterfactual model is too simplistic to produce reliable predictions. The model has only two explanatory variables–gas price and a time trend—which fail to control for many other causes of differences and changes in electricity prices. Second, using this model to project 2001-03 electricity prices is problematic because the crucial explanatory variable (fuel price) is already known to be statistically insignificant. The model also represents out-of-sample prediction which, as discussed earlier, is less reliable under the best of circumstances than a within-sample approach. Finally, the gas cost variable that is used for prediction is said to be a regional price index, rather than state-specific prices. This implies that the model assumes that the predicted prices in all states in a region move in lockstep in the post-restructuring years—an unrealistic assumption.

Third, Fagan's benchmark models of industrial prices appear to have been estimated for each individual state, rather than for all states together. If so, the model would have two explanatory variables and only eight observations for each state—too few for a meaningful estimation with reliable results. Fourth, Fagan's estimation on the difference between actual and predicted prices is really a simple correlation between the two series. Fagan reports an insignificant negative effect of restructuring, but that is difficult to reconcile with his first empirical finding, which was that the price differences were smaller in deregulated states. Various causal factors included in the differences estimation should arguably have been included in the initial regression, which was intended to isolate causal factors. But a number of these independent variables are quite doubtful. Some variables are related to one another, and the crucial restructuring variable is defined only as a "state's restructuring status."[19]

3.5 Law and Economics Consulting Group (2006)

The Law and Economics Consulting Group (LECG) report *Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges* acknowledges problems with many common approaches to assessing restructuring. It notes, for example, that interpreting post-reform price as an indication of the effects of reform fails to account for rate reductions and freezes, stranded cost recovery charges, and other factors. It concludes that a new approach is necessary, and proceeds in three steps.

[19] Fagan observes that this variable is likely to be endogenous with price, and he instruments for it in the actual regressions, but he offers no explanation for his choice of instruments.

First, in order to distinguish the impact of changes in fuel prices and other economic trends from the effects of coordinated markets, the study uses pooled time series-cross section data on average annual residential electricity prices of utilities in coordinated versus traditional markets for the period 1990-2004. The relationship between these two sets of prices becomes the basis for predicting what prices in coordinated markets would have been in the absence of reforms. Second, the study controls for the effects of retail access programs that often went into effect at the same time by examining utilities that existed in both traditional and coordinated markets but were unaffected by retail access programs. LECG (2006, p. 18) uses a sample of municipal and cooperative utilities that had a continued obligation to serve (i.e., no retail competition) throughout the study period, to isolate the impact of coordinated markets on retail prices. Third, the analysis proposes to take into account the impact of differences in gas dependence among utilities by segmenting the sample utilities into those in a gas dependent region and a region with little gas dependence in 1990 (prior to the time that the policy changes were implemented).

A regression model is then estimated. Despite some anomalous findings acknowledged in an appendix, the text focuses on favorable results and concludes that average retail rates arising from implementation of coordinated markets fell by between \$.50 and \$1.80 per megawatt hour.[20] The study generalizes these rate impacts to all consumers and to all investor-owned utilities in regional transmission organization (RTO) regions, concluding that customers of PJM and the New York Independent System Operator (NYISO) enjoy benefits ranging from \$430 million to \$1.3 billion per year (LECG 2006, p. 36).

While the LECG study addresses some limitations of the most common methodologies that have been used to assess the effects of restructuring, its own study exhibits a number of problems.[21] First, the study is not precise about what it is evaluating, focusing almost exclusively on locational marginal pricing but discussing results in terms of “coordinated markets.” These are not the same thing. Second, LECG excludes most states and regions, leading to a final analysis of a very few, and quite possibly atypical, cases. For example, the comparison between traditional and coordinated markets for gas-dependent regions is essentially a comparison of one state—Florida–with PJM and NYISO and, indeed, not all of the latter.

Third, in the econometric model, there is no indication of a correction for inflation for the electricity price data, no real explanation for including the explanatory control variables or for omitting certain others, and no rationale for assigning fractional values to the crucial coordination dummy variable for certain years and states. In addition, including sales on the right-hand-side of the price equation creates simultaneity bias in

[20] LECG (2006, p. 36). In the basic model with dummy variables for utilities, the Coordination variable is negative and significant for gas-dependent regions, while for non-gas-dependent regions it remains negative but is insignificant. When the utility dummy variables are replaced with each utility’s 1990 average residential rate (an alternative specification that assumes that otherwise unmeasured utility-specific differences are due only to their relative rates in 1990), coordinated markets now matter in both cases, but with a *larger* magnitude and significance in the case of non-gas-dependence.

[21] As was done in the case of other quantitative studies, LECG was asked to provide its data so that further checks and analyses could be undertaken. LECG staff indicated that the data would be made public shortly, but that did not occur in the months before this review was finalized.

the estimates and undermines the reliability of the results. No explanation for including the variable for the percent industrial load is offered and its statistical significance varies. Finally, among model specification issues, the LECG study excludes the price of natural gas with the explanation that it may be endogenous. But the alternative control technique of separating gas dependent versus non-gas dependent states depends on certain assumptions, many of which do not hold.

Fourth, the LECG study acknowledges a number of econometric issues that it resolves in less-than-satisfactory ways. It reports that there is no statistical basis for the distinction between gas-dependent and non-gas-dependent states, but it nonetheless provides only the results from the split sample. Correction for heteroskedasticity (which might result in an over-statement of the statistical significance of effects) weakens the results that favor coordinated markets, but the report relies upon uncorrected results showing more significant price reductions from coordinated markets. Also, the study notes that a few utilities constituted outliers in the overall results, altering the magnitudes and statistical significance of the estimated effects of coordination. But only one set of results is presented, making it difficult to determine exactly how sensitive the results may be. As a result of these and other econometric issues, the LECG study relies on many estimated coefficients that fall short of conventional levels of statistical significance and others that are unstable from specification to specification.

Fifth, the LECG study relies on three striking, sweeping, but altogether unsupported presumptions: (1) that its chosen states (or in one case, just a single state) accurately represent all states with particular types of market and degrees of gas dependence; (2) that its results for residential customers generalize to all commercial and industrial users; and (3) that having taken munis and co-ops as benchmarks, quantitative results nonetheless extend to all types of utilities. None of these three assumptions, crucial for LECG's final estimate, is obviously justified.

All in all, despite greater appreciation of problems with other studies, LECG's own effort errs in its methodology and execution in ways that undermine its conclusions.[22]

3.6 Conclusions With Respect to Econometric Models of Prices

Despite the fact that the foregoing five studies all rely substantially on econometric modeling, there are striking differences among them, as summarized in Table 1. As is evident, each employs somewhat different price variables, different criteria for the restructuring event, a different list of control variables, and different types and numbers of observations. Two employ out-of-sample prediction, while the others use the more reliable within-sample technique. Substantively, four of the five come to essentially favorable overall judgments about restructuring. However, there is inadequate attention in these studies, among other things, to the important data issues of post-restructuring price freezes, stranded cost recovery charges, and excess capacity, and hence none offers very reliable and convincing evidence with respect to the effects of restructuring.

[22] Well after this report was written, LECG revised its own report, seeking to answer methodological criticisms that were made of its previous version. Despite much effort, the major criticisms made herein still hold.

Table 1 Summary of econometric studies of price

	CERA	JOSKOW	TABER et al.	FAGAN	LECG
Dependent variable(s): Electricity Price	Regional CPI for electricity	Residential Industrial	Residential Commercial Industrial Overall	Industrial	Residential
Causal variables	1997	PURPA Independent generators Retail choice	ISO membership	Year Restructuring	Coordinated market
Control variables	Fuel price Capital cost	Fuel price Capital cost Generation type (2) Average usage	Fuel price Generation type (6) Climate	Fuel price	Utility size Sales per customer Industrial sales Gas dependence
Number, type of observations per regression	4 regions × 16 years = 48	51 states × 34 years = 1,734	Approx. 85 utilities × 14 years = 1145	8 years	Numerous municipal, coop utilities over 15 years
Prediction method	Out-of-sample	Within sample	Within sample	Out-of-sample	Within sample
Recognition of Price freeze	No	No	No	No	Recognizes all, attempts to address
Stranded cost	No	Recognizes	No	Adjusts	
Excess capacity	Adjusts	No	No	No	
Brief conclusion	Predicted prices below actual in all regions. Separate index of deregulation related to savings, except in Western U.S.	Variables for retail competition and share of exempt wholesale generation both associated with lower retail prices.	Variables for membership in auction-based ISOs do not indicate lower prices.	Predicted prices higher than actual prices more often in restructuring states than without restructuring, but effects dominated by other factors.	Predicted price in LMP-based markets found generally to be lower.

4 Five Comparative Studies of Price and Cost

This section discusses five studies that undertake a quantification of the price or cost effects of restructuring with techniques that are not fundamentally econometric in nature. Two such studies–those authored by CAEM and by Apt–are essentially comparisons of prices before and after restructuring. The studies by Synapse and GED construct alternative prices or costs from accounting data to infer the effects of deregulation. The quantitative analysis in the ESAI study rests on a simulation of the counterfactual prices. We briefly summarize and comment on each.

4.1 CAEM Study (2003)

The study *Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region*, calculates the benefits from restructuring the PJM market. It is based on the working assumption that "restructuring redistributes producer surplus [the profit gain] from regulated utilities to competitive suppliers, but produces no net change" (CAEM 2003, p. 43). CAEM offers a list of ten possible benefits from restructuring, such as a decrease in outage rates, construction of new capacity, and increased reliability of the system.

The benefits calculation method is a trivial comparison of residential, commercial, and industrial prices in PJM states in 2002 versus 1997. Multiplying the change in price by PJM electricity generation in 2002 gives an estimated $3.3 billion in savings for the region in that one year. Notably, CAEM also claims as a benefit from current restructuring efforts the present value of future electricity cost savings that will result from current efforts. These additional benefits are estimated by assuming the same price reduction but a growth in electricity generation over time in accordance with Energy Information Administration estimates. This procedure yields an estimate of consumer benefit in present value terms of $38.8 billion.

CAEM makes one effort to separate the effects of restructuring from other factors by examining changes in electricity prices between 1997 and 2002 in three neighboring states that did not restructure their electricity sectors, and for the United States as a whole. Since prices generally declined during this period, the report proposes to subtract from the gross benefits within PJM those that arose in those neighboring non-restructured states. The implication is that any residual must be due to deregulation within PJM, although the study does caution that other factors such as fuel prices and state environmental regulations might also differ among states. It concludes that $10.1 billion in savings in present value terms would have occurred even in the absence of reforms, leaving $28.7 billion attributable to restructuring.

There are a number of major limitations of the CAEM study.[23] One is the inadequacy of comparing PJM prices in 2002 with prices in 1997, with the difference (adjusted for inflation) attributed to restructuring. Failure to control for other possible causes makes such attribution erroneous. Second, the study does not state precisely what "restructuring" means, why it would have caused the price effects examined, and why

[23] These comments include some observations made in Christensen Associates (2003).

the measured effects of restructuring in PJM are at the wholesale level while the study addresses only retail prices.

Third, the study fails to correct for the distorting effect of rate reductions and freezes and of excess capacity, even as it concedes that, for example, New Jersey consumers enjoyed 15 percent lower prices due to the regulatory bargain.[24] On the other hand, the study adjusts retail rates in Pennsylvania for such stranded costs, thus crediting restructuring for additional, yet-to-be-realized benefits. This adjustment has the effect of reducing post-restructuring consumer costs by \$8.6 billion, or 30 percent of the total (CAEM 2003, Table A1). Such adjustment is desirable, but in this case the study makes the one adjustment that favors restructuring, while ignoring others that run counter to this conclusion.

Fourth, the assumption that consumer benefits will continue at the same rate indefinitely cannot be justified. From the outset those reductions were made to be temporary, and indeed, some had started to expire before this study appeared. Finally, the study's effort to adjust the calculated benefits for factors other than PJM restructuring itself is inadequate. Using a "difference-in-differences" technique, CAEM compares savings within PJM to savings over the same period in three nearby non-restructuring states. But the present value of cost savings as a percent of 2002 costs was 6 percent (Kentucky), 45 percent (North Carolina), and 76 percent (Tennessee), making these states suspect as controls.

4.2 Apt Study (2005)

The study *Competition Has Not Lowered U.S. Industrial Electricity Prices* also focuses on industrial prices. The study first calculates the average annual rate of industrial price change for Connecticut, Massachusetts, Maine, New Hampshire, New York, and Rhode Island from January 1990 to one month prior to the beginning of each state's "phase-in period" for industrial competition. That calculation of annual pre-restructuring price change implies a 0.9 percent price increase, while the corresponding annual rate after the phase-in of competition was a decrease of 1.7 percent. Apt recalculates these changes without Maine's anomalous data and obtains a pre-competition increase of 0.8 percent and a post-competition increase of 2.0 percent for the remaining states. Apt concludes that these data do not support the proposition that restructuring reduced prices.

In the next step of his analysis, Apt calculates the average annual rate of change in industrial prices for each of 20 states that restructured their electric power industry, first for the period prior to their restructuring and then following restructuring. Their mean pre-restructuring price change was a 0.4 percent increase per year, rising slightly to 0.5 percent after restructuring. (Omitting Maine results in a pre-restructuring value of 0.3 percent and a post-restructuring value of 1.7 percent.) Apt compares these values to those for all 50 states plus the District of Columbia. For the latter, the rate of

[24] Interestingly, this 15 percent figure is precisely the amount of the rate reduction calculated by CAEM as due to restructuring. Simply put, it would appear that the entirety of the benefit found by CAEM for these consumers was nothing but the initial rate deal.

price change in the pre-restructuring period (taken as April 1998 through 2000) was a negative 0.4 percent, followed by a later increase in price at the annual rate of 0.4 percent. These comparisons also provide no evidence favoring restructuring.

Finally, Apt examines individual state data more closely, calculating the difference between the pre- and post-restructuring annual rate of change in industrial price for each. A regression run on these differences in the rate of price change, with "restructuring" as the independent variable confirms the absence of a relationship between restructuring and price change in these data.[25]

The Apt study pursues what appears to be a relatively straightforward approach to the question of the effects of electricity restructuring. But the study still raises several concerns: One is that the outcome variable for Apt's study–the annual rate of price change–does not seem to be a well-chosen criterion for measuring the performance effects of electricity reforms. Successful reforms should bring about efficiencies, competition, and ultimately a lower level of price, but not necessarily prices that increase (or decrease) at a different rate.

Second, the study's method for calculating the annual rate of price change is likely to introduce errors in variables. For example, the period over which the annual rate of change variable is calculated differs for each state, creating a mismatch and errors in the variables. Then as noted previously, restructuring is a process that unfolds progressively so that using a single point in time converts a continuous variable into a dichotomous one, introducing further errors. The phase-in period also varies enormously across states, ranging from March 1998 in Massachusetts to March 2002 for Oregon and does not deal with price changes independent of restructuring during 2000 and 2001.

Third, by annualizing the rate of change, Apt overlooks possibly relevant differences in the rate of price change in certain years. For example, if prices were beginning to fall just prior to restructuring, annualization over a longer period might result in an incorrect benchmark for evaluating the post-restructuring price. Alternatively, annualization could capture the more discrete change due to restructuring. Fourth, the focus on differences in annualized price change before and after restructuring creates difficulties in controlling for other possible influences. Apt picks two time periods to control for the possible influence of other factors on electricity prices during this time, but those periods are arbitrary and different from any of the periods over which the same calculation is made for restructuring states.

Finally, the study chooses to address industrial prices in order to avoid issues such as price freezes, stranded costs, etc., that confound residential prices. But as noted earlier, industrial prices in many states were also subject to rate reductions and freezes, so that the post-restructuring data relied upon by Apt are not free of such difficulties.[26]

[25] Jay Apt graciously provided these data, permitting replication of his results.

[26] Of course, since Apt ostensibly finds restructuring to have had no effect, failure to correct for post-restructuring freezes–a correction that would raise such rates–should not reverse his conclusion. In any event, excess capacity and stranded costs remain as issues.

4.3 Synapse Energy Economics Study (2004)

The study *Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs* analyzes electricity generation costs before and after two changes: (1) the retail restructuring in states within the PJM region, and (2) the restructuring of the wholesale markets in PJM with the introduction of markets for energy, capacity, and other services, beginning in 1998. Specifically, this study compares the actual wholesale power costs (WPCs) paid by utilities under deregulation to the implied cost of generation that would have occurred if regulation had continued from 1999 to 2003. To implement this approach, Synapse engages in extensive reworking of individual company financial and operations data to construct the implied generation service costs for three PJM companies.

The energy market component of actual wholesale power costs are represented by load-weighted locational marginal prices.[27] Locational prices are calculated separately for each of three utilities – Jersey Central Power & Light (JCPL), Pennsylvania Electric Co. (Penelec), and Delmarva Power & Light – to capture their different purchase cost experience, while capacity costs are essentially the same for each company in PJM East in any given year. The results show that PJM East average costs have varied from a low of \$30.72 per MWH in 2000 to a high of \$42.64 in 2003, costs for Delmarva and JCPL are close to the PJM East averages in each year, while Penelec's costs are systematically lower.

The next part of the report confronts the task of constructing counterfactual generation service costs (GSC) for pre-deregulation years. GSCs reflect the utilities' generation capital financing and operating expenses, as calculated for a base year (1996) under cost-of-service regulation. GSCs for subsequent years are obtained by indexing their initial values and calculating them for all three companies for five years, yielding the second set of costs needed for the comparison.

The Synapse report notes two unavoidable defects in the data: (1) the indexed GSCs contain stranded costs, and (2) the capacity surplus in PJM distorts recorded costs. That said, GSC costs were higher than WPCs for four years out of five for Delmarva and Penelec, and for all five years in JCPL's case. In addition, the comparison indicates that the actual wholesale costs were more volatile than the counterfactual ones. Based on these observations, the study draws its main conclusion that "while PJM deregulated costs fluctuate year-to-year, on average, the deregulated rates appear to have been lower during this five year period than those generation rates that would have existed under a business as usual, regulated environment" (Synapse 2004, p. 32).

The Synapse methodology–constructing counterfactual costs in the absence of restructuring–is a novel approach to the question of the effects of reform. Its strength lies in the ability to use actual data to infer such costs, but therein lies its limitations as well. Synapse states some caveats about its methodology and results. One is that indexed GSCs rely on highly simplified assumptions (Synapse 2004, p. E5-1, p.32). A second is that WPCs are calculated based on locational wholesale prices and hence include some congestion-related transmission cost, whereas the GSCs do not.

[27] These are prices that reflect the differences in the costs of delivering electricity to different parts of PJM, known as nodes.

Third, WPCs do not necessarily translate into actual prices to customers, as retail adders, marketing costs, and market power may divorce the two series. Fourth, WPCs in these years have been unusually low due to capacity surpluses in the PJM region. And fifth, the study examines only three utilities, which cannot be assumed to representative without further study. It is interesting to note that all of these caveats, except transmission costs, exaggerate the likely cost advantage of the WPCs over the constructed GSCs to the point that the measured advantage of post-restructuring costs might be substantially narrowed or even reversed.

Other concerns also arise: First, the constructed counterfactual costs are largely assumption-driven, some of which seem reasonable but others are harder to assess without sensitivity analysis. Second, Synapse uses cost allocation formulas to apportion costs in calculating GSCs – formulas that have a significant element of arbitrariness in them. Third, certain assumptions concerning indexing GSCs for future years are questionable. For example, the study states that all new energy needed for load is obtained at the PJM market price, which may not provide an accurate reflection of the equilibrium price during the study period (Synapse 2004, p. 32). Synapse also uses FERC Form 1 data to estimate the prices of purchases and sales, noting in the process that these might not be correct since the actual prices in many of these years reflect deregulation itself.

4.4 Global Energy Decisions Study (2005)

In its 2005 report, *Putting Competitive Power Markets to the Test: The Benefits of Competition in America's Electric Grid–Cost Savings and Operating Efficiencies*, Global Energy Decisions (GED) analyzes three aspects of wholesale electric market restructuring in the PJM Eastern Interconnection region: the consumer benefits from the introduction of unregulated wholesale electricity suppliers, the effect of restructuring on the operating efficiency of power plants, and the benefits of PJM expansion in 2003-04.

With respect to wholesale power deregulation in the Eastern Interconnection, the study attempts to quantify consumer benefits by comparing costs under two scenarios. The first, termed the "With Wholesale Competition" case, is based on the actual operating data from wholesale power markets for the period 1999-2003. These markets include the competitive sector (i.e., exempt wholesale or merchant generating units that sell their energy and capacity on the open market), and a regulated sector (i.e., traditional regulated utilities obliged to serve native load retail customers with their own generation plant and with power purchased from the competitive sector).

The second case, termed "Without Wholesale Competition," involves the construction of counterfactual cost data and a simulation of market operation (GED 2005, p. RS-3). The counterfactual involves the replacement of power currently purchased by utilities with power from regulated generation plant plus power acquired at pancaked (i.e., involving double marginalization) transmission rates. GED simulates market operation in 29 market areas, delineated by critical transmission constraints in the Eastern Interconnection and obtains cost estimates that would have risen under continued regulation. The outcomes of two models are compared, with the difference representing estimated consumer benefits from wholesale restructuring. Cumulatively over the five-year study period, consumer benefits are said to total \$15.1 billion over the whole study period.[28]

The second section of this report evaluates the operating efficiency of power plants before and after wholesale competition. Its compares various measures of operating efficiency over the 1999-2003 period for the entire U.S. generation "fleet" and concludes that improvements were due to competition. In the last part of the report GED examines the benefits for wholesale power customers from the 2003-04 westward expansion of PJM measured as simply the reduction of pancaked wheeling charges between three new member utilities and PJM energy markets. The methodology compares actual production costs between PJM members in 2004 versus the "without competition" case,[29] resulting in \$85.4 million of annualized production cost savings for the Eastern Interconnection and \$69.8 million for PJM.

The GED study on consumer benefits combines two different methodologies–constructed costs, and market simulation–each based on a number of crucial assumptions. Several of these are problematic.[30] First, as previously noted, restructuring has been a multi-faceted process over time, but this study takes the exaggerated view that "without competition" means that no reforms whatsoever have taken place. Some major benefits that GED attributes to restructuring (e.g., elimination of pancaked transmission rates) are attainable without the entire wholesale market restructuring package and would likely have occurred without it.

Second, the study's assumption of no transmission constraints and hence zero transmission costs within each of the 29 market areas in the Eastern Interconnection is incorrect, sufficiently so as to introduce errors into its cost estimation. Third, GED's estimated \$15.1 billion in benefits from competition derives from two doubtful sources. More than half of that amount–\$8.9 billion—results from shifting expenses and the risks of building power plants from utility consumers to the competitive plant owner/operator/supplier" (GED 2005, p. RS-20). These losses borne by new generators represent a temporary post-restructuring disequilibrium that will persist only in the unlikely event that there is a never-ending supply of misinformed investors who are prepared to enter, build, and take losses on generation indefinitely.

Fourth, the other major part of the estimated benefit derives from the assumption that new plants would have been built by regulated utilities at the same capital cost as in the past. This \$5.8 billion cost of regulation far exceeds that under competition. But regulated utilities almost surely would have adapted their generation mix to changing fuel costs and other factors, rather than replicating historical practice. Moreover, the competitive sector's dependence on new gas-fired generation may have seemed prudent during the study period, but subsequent high natural gas prices may undermine that advantage. Overall, these two factors–temporary generator losses and excessively

[28] An alternative "Low-Capital Cost" variation, based on a different mix of new generation plant, results in a benefit "floor" totaling \$9.4 billion.

[29] The reason why simply adding these utilities to PJM constitutes "competition" is not made clear.

[30] These comments include some observations made by Spinner (2005) and by Christensen Associates (April 2006b).

costly new capacity, both of which are doubtful–account for $14.7 of the $15.1 billion in total gains from restructuring that this study finds.

The GED study's exercise in assessing changes in the operating efficiencies of the North American generation fleet is also somewhat misguided. Its universe consists of all plants in the U.S., Canada, and Mexico but no insight is provided into factors that might affect non-U.S. plants, and whether they are appropriately included in the comparison group.[31] In addition, the study categorizes plants into traditional and competitive groups based on whether they are subject to retail rate regulation. These definitions differ from those advanced in the first part of this study.

Finally, the study's exercise is called "The Impact of Regional Transmission Organizations," but in reality it deals only with expansion of the PJM market. The exercise only calculates the predictable results of eliminating pancaked transmission rates–something that could be accomplished without adding additional complexity to RTOs. This or any other "benefit" would require measuring any offsetting costs, which appear to be substantial.

4.5 Energy Security Analysis, Inc. Study (2005)

The study *Impacts of the PJM RTO Market Expansion* by Energy Security Analysis, Inc. (ESAI) (commissioned by PJM itself) evaluates the impact of PJM's expansion both on its original service territory and on its expanded territory following the addition of member utilities starting in 2002. ESAI casts PJM as a broad "agent of change" in the industry, altering market rules, interconnection rules, and transmission system management rules over a larger and more diverse set of generation and transmission assets. The study states that PJM expansion has had various important consequences (ESAI 2005, p. 5) than a simple reduction in energy price, including the degree of liquidity in the market for power contracts. Data series on short-term market volumes, longer term market volumes, bid/ask spread, and market bias show pronounced gains immediately after restructuring in 1998, declines in the 2001-02 period, and then some recovery. ESAI concludes that PJM expansion is associated with "$1.4 billion per year…or $15.7 billion over a 20-year planning period…"(ESAI 2005, p. 39).

The next section of the study assesses the reliability effects of integration by examining the PJM capacity market. ESAI values the PJM reliability pricing model (RPM) by predicting the increase in the energy charge that would otherwise occur due to capacity reductions, then assumes RPM will prevent all of that increase. It concludes that this program will provide between $500 million and $5 billion in annual savings. Next, the ESAI report addresses the energy price effects of PJM integration using power flow simulations. ESAI acknowledges that the integration at issue is essentially the flow of low-cost energy from PJM West to PJM East, leading to an estimated energy price difference of $0.78 per MWH and a $500 million reduction in area energy costs. The study reinforces this estimate by examining generation dispatch benefits (pre- and post-PJM integration), price trends in PJM and associated markets, and trends in heat

[31] Unless, of course, some plant in Mexico or Canada has been subject to restructuring. The GED Study is silent on issues of numbers of plants, location, restructuring status, etc.

rate and management of regional price risks with the help of financial transmission rights (FTRs).[32] A final section of the study addresses the effects of PJM expansion on electricity trading volumes and on innovation, concluding that increases in power flow transfers between PJM's original territory and its new regions is a measure of the benefit of expansion.

The ESAI study consists of an estimate of energy cost savings from PJM integration and a variety of other effects that it claims are ultimately more important, both of which are potentially problematic.[33] First, the energy cost estimation technique is a "black box." Power flow simulations are useful in implementing operating protocols and anticipating various contingencies, but they are not designed as methods for quantifying costs of alternative structural designs. Second, problems with ESAI's methodology are also confirmed by certain paradoxical results that it generates. ESAI's simulation finds that in some cases global optimization is actually inferior to suboptimization–an apparent error in the simulation process and of the benefits estimate that it produces.

Third, many of the other benefits of PJM expansion (e.g., changes in liquidity, efficiency of forward prices) on are based on mere assumption, speculation, or unfounded assertion of causation and have occurred in all power markets. Fourth, the study endorses FTR markets as a hedging mechanism based on their apparent effectiveness in the short term but since FTR contracts extend only for one year, they are irrelevant as a hedge against transmission price risk in the longer term.

4.6 Conclusions With Respect to Other Quantitative Studies of Restructuring

These five quantitative but non-econometric assessments of electricity restructuring differ in many ways. As shown in the summary presented in Table 2, they posit different performance variables, use different restructuring variables, control for different other influences, have different types and numbers of observations, and draw on different methodologies. Some of their judgments in these areas are defensible, others less so.

Most involve some type of fairly straightforward comparison of prices or costs across time or place. Often these studies use a "difference-in-differences" approach, which requires care in selecting the control group. Others involve constructed or counterfactual prices or costs based on various assumptions and judgments. Still others rely on simulations to obtain estimates of performance outcomes. Most have significant limitations to their analytical techniques, diminishing the reliability of their conclusions, but few acknowledge those limitations. It should nonetheless be noted that the methodologies used in these studies represent a range of interesting and promising approaches that, with appropriate care, might be used in further evaluations of restructuring.

[32] FTRs in theory provide the holder with the rights to revenues received for congestion on a given portion of the transmission system. Congestion revenue is paid when more expensive generators must be dispatched because there is no room on the transmission lines to accommodate power from less expensive sources.

[33] These observations draw in part on Christensen Associates (2006a, p. 1).

Table 2 Summary of Comparative Studies of Price and Cost

	CAEM	APT	SYNAPSE	GED	ESAI
Performance variable	Prices: Residential Commercial Industrial	Rate of change in industrial prices	Wholesale costs	Retail prices	Wholesale price
Restructuring variable	None	None	None	With, without wholesale competition	PJM expansion vs. no expansion
Control variable(s)	Non-restructuring states	Non-restructuring states	Constructed counterfactual	Constructed counterfactual	Simulated counterfactual
Observations	PJM states, 1997 and 2002	All states, 1990 - 2003	3 PJM utilities	Eastern Interconnection, 1999 -2003	PJM East vs. PJM West
Analytical method	Differences in differences	Differences in differences	Comparison	Comparison	Simulation, comparison
Brief conclusion	Substantial savings found in restructuring PJM territory	"Restructuring" not significant in regression on differences in rates of change.	Actual costs less than implied regulated costs, although not necessarily large differences	Substantial consumer benefit from restructuring	Significant cost reductions in larger control area

5 Other Issues in Electricity Restructuring

The preceding sections have reviewed ten quantitative studies of electricity restructuring. Most of the comments have been directed at the manner in which the studies handle various methodological issues in comparing performance under restructuring to prior conditions. In addition to how well these studies answer the questions they *do* ask, it is also important to recognize three major questions that they generally do *not* address.

5.1 Market Structure, Market Power, and Mergers

Restructuring the electric power sector has unleashed a wave of mergers and questionable practices; some of these changes are serious enough to raise a very real question about the prospects for competition in electricity markets. There are four related concerns. The first is vertical market structure. Economic studies have shown that the traditional vertical integration of utilities serves to capture substantial efficiencies of coordination among the generation, transmission, and distribution stages of production, and competition-promoting de-integration has proven to be a costly undertaking (Kwoka 2002). A second concern is over market power. FERC's *2004 State of the Markets Report* finds that the largest 10 generation companies now account for anywhere from 74 to 83 percent of generation in all regional markets but California and the Midwest.[34] Various studies (e.g., Mansur 2001; Bushnell and Saravia 2002; Borenstein et al. 2002; and Tucker 2002) have documented a persistent gap between prices and marginal costs–a standard measure of market power–in many regional markets, including where RTOs exist.

Third, more than 70 mergers involving electric utilities occurred in the 10 years from 1994 to 2003, many of these involving distribution utilities. Preliminary evidence from the distribution mergers that dominated the 1994-2003 period refutes the contention that better-managed utilities were seeking out poor performers for improvement and that the acquisition therefore resulted in efficiency gains to the acquired company (Kwoka and Pollitt 2007). Last is unilateral withholding. Unlike traditional concerns over competition among a few sellers, withholding does not involve cooperation or collusion. Rather, its power derives from the ability of a single owner of generation plants to shut down part of its operations and thereby to raise market price sufficiently so as to recoup more than any lost profit on the shuttered capacity from the added profit on the still operational units.[35] Unilateral withholding is especially pernicious market behavior since it is difficult to prove and does not appear to be readily controlled by antitrust or regulation. These questions of competition are directly related to effects of and prospects for restructuring, yet they receive little or no attention in these studies.

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[34] FERC, *2004 State of the Markets Report*, June 2005.

[35] For formal analyses, see Kwoka (2001); Joskow and Kahn (2002); and Wolak (2003).

5.2 RTO Costs, Governance, and Effectiveness

RTOs are novel institutions designed to incorporate and extend the best features of independent system operators. A total of six RTOs have now been approved and operate over more than half of the country's electric power systems, but a number of concerns have arisen. For example, RTO costs have grown and continue to increase to a worrisome degree. Aggregating investment and operating costs for day-one and day-two markets to all six ISOs, Lutzenhiser calculates the annual total to be on the order of $1 billion in 2004 or $2.5 billion if extrapolated to the national electricity market (Lutzenhiser 2004). This equals FERC's own estimate of the likely total benefits of RTOs.[36]

Second, RTO governance has raised further concerns. Governance varies among the individual RTOs, but involves an independent board of various stakeholders. Apart from board members' sometimes divergent objectives, its very task is something of an oddity–the nonprofit operation of assets that it does not own. Such concerns have led one group of interested parties to plead for the FERC to "view RTOs for what they are–regional monopolies that it must vigorously regulate, not regional extensions of the Commission itself" (APPA 2004, p. 17).

Finally, RTO effectiveness is much in dispute. It is widely understood that RTOs have encountered major difficulties in resolving transmission congestion and have largely failed to encourage transmission investment. The PJM*2005 State of the Market Report*, for example, noted that "congestion costs have ranged from 6 to 10 percent of total PJM annual billings since 2000, totaling $2.09 billion in calendar year 2005…"[37] Despite these substantial congestion charges, transmission line loading relief actions were reported to be four to five times more numerous in the U.S. in 2000 and 2001 compared to earlier years. In the longer term, RTOs have proven largely ineffective in new transmission planning and development (e.g., USDOE 2002; TAPS 2004). While the issues surrounding RTOs would seem necessarily to be part of any comprehensive study of restructuring, they receive little attention in these studies.

5.3 Service Quality and Reliability

One neglected issue in these evaluations of restructuring is any possible effect on service reliability and quality. Such effects would not be surprising, as restructuring has replaced the vertically integrated utility's "obligation to serve" with contractual arrangements and information and coordination links between generators and distributors have been severed. This altered structure and incentives indisputably can affect outcomes, as is evidenced by documented examples of strategic withholding of capacity, discussed above, and by studies of the quality effects of incentive regulation in electricity and other markets (e.g., Ter-Matirosyan 2003).

[36] Order 2000, FERC, pp. 95-96. The benefits anticipated by FERC were based on studies of the effects of dispatch over a wider area, on the assumption that offer prices were at marginal cost. This has not proven generally to be the case.

[37] PJM *2005 State of the Markets Report*, p. 45.

6 Concluding Observations

The ten studies covered in this review represent perhaps the most prominent recent efforts to determine whether this consumer benefits objective has been or is being achieved. Eight of the ten find efficiency gains in wholesale markets or retail price benefits from restructuring. The eight favorable studies are those authored by the Center for the Advancement of Energy Markets, Synapse, Global Energy Decisions, Energy Security Analysis, Inc., Cambridge Energy Research Associates, Joskow, Fagan, and Law and Economics Consulting Group. However, those by Synapse, Joskow, and Fagan substantially qualify their conclusions or methodologies. The remaining two articles–by Apt and Taber et al–come to unfavorable conclusions about the effects of restructuring.

The focus of this review has been on the strengths and limitations of the specific methodologies used in these studies and hence on the confidence that one should place in their conclusions. In that regard, this article has documented significant methodological deficiencies in virtually all of these studies. In some instances the deficiencies could be remedied and the results of an improved study would be of interest, but in other cases the defects are sufficiently serious as to render them suspect. In addition, this review has noted several important aspects of restructuring that should receive more attention. These studies are important since they represent the first wave of evaluations of electricity restructuring up to this point in time, and also provide guidance on further possible reforms. However, it is not clear that these studies should serve as a sound basis for further ill-defined "deregulation" or "competition" solutions to the present difficulties in electricity markets.

In conclusion there are three additional observations worth making. First, this paper has not surveyed all studies and evidence that bear on the effects of electricity restructuring. For example, some studies have found efficiency gains in divested generation plants, although others respond with evidence that stronger incentives rather than divestiture may be responsible (e.g., Markiewicz et al. 2004; Bushnell and Wolfram 2005). Such other studies constitute a broader literature related to restructuring not surveyed here. Second, the ten studies reviewed consist of six consulting reports plus four studies authored by academics. It is interesting to note that all six consulting reports report favorable results. Two of the four academic studies, by contrast, offer negative overall assessments. If the latter unsponsored studies can be viewed as more independent of interested parties, then one might conclude that independent views of restructuring are considerably more evenly split than the overall number of studies might suggest.

Finally, we note that despite the critique of these studies contained herein, a sound study is by no means impossible. Some deficiencies are quite correctable and issues that compromise one study may be found adequately addressed in another. For example, stranded cost issues or the choice of benchmark states are problematic in some studies, but others do a satisfactory job in dealing with them. Matters like excess capacity are more difficult, but a study of the price impact of excess capacity could be undertaken. Alternatively, an analysis of the sensitivity of overall results to a range of possible effects from capacity would be informative and perhaps sufficient. A study that takes these and other issues fully into account is entirely feasible.

It may be hoped that the foregoing discussion will have two desirable effects, one cautionary, the other constructive. The caution concerns the debate about electricity restructuring to date and in the future. To the extent that the debate looks to these studies for conclusions about past policy or for insights regarding future policy directions, it should be recognized that these studies do not constitute a particularly reliable foundation for those purposes. More constructively, the critiques of these studies suggest improved methods for further study of electricity restructuring. By remedying the deficiencies of existing studies, future studies may be methodologically more sound and substantively more convincing, in which case they will serve as better guides to policy initiatives in this most important industry.

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Emily Hammond
George Washington University Law School

Jim Rossi
Vanderbilt University

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STRANDED COSTS AND GRID DECARBONIZATION

Emily Hammond[*] & Jim Rossi[**]

ABSTRACT

Energy law is well equipped to facilitate the transition to a decarbonized grid. Over the past half century, energy law has endured many stranded cost experiments, each helping firms and customers adjust to a new normal. However, these past experiments have contributed to a myopic regulatory approach to past stranded cost recovery by: (1) endorsing a preference for addressing all stranded costs only after energy resource investment decisions have been made; and (2) fixating on the firm's financial costs and protection of investors, rather than on the broader impacts of each on the energy system.

The current transition to decarbonization is already giving rise to stranded cost claims related to existing energy assets like coal-fired and nuclear power plants. New energy infrastructure investments—such as natural gas pipelines and natural gas-fired power plants--will also face stranded cost issues once they have provided the expected bridge to a clean energy future.

We see the transition to grid decarbonization as a propitious opportunity for energy law to improve its approach to stranded cost compensation for investor risks. Unlike with past energy industry changes, where stranded costs were routinely addressed after investment decisions were made, it is important for regulators to address stranded costs now, at the outset of the transition to a decarbonized grid. As in the past, stranded cost compensation will prove important, if not essential, to this impending energy transition. But it should be approached in a manner that helps to overcome the obstacles to a decarbonized grid, reassure investors in new infrastructure without distorting capital signals to favor legacy resources, and recognize important energy resource attributes that competitive markets fail to price.

INTRODUCTION

Change is at the center of today's debates regarding how to transition to a low-carbon energy infrastructure. Achieving an 80% reduction from 1990 carbon emission levels by the year 2050[1] will require increased renewables penetration,[2] near-term

[*] Professor of Law, The George Washington University Law School.
[**] Professor, Vanderbilt Law School.

[1] This is roughly the level of emissions reduction necessary to meet the commonly agreed upon goal in the international community of limiting anthropogenic increase in global mean surface temperatures to less than 2 degrees Celsius. *See* PATHWAYS TO DEEP DECARBONIZATION IN THE UNITED STATES xi (November 2014), at http://unsdsn.org/wp-content/uploads/2014/09/US-Deep-Decarbonization-Report.pdf [hereinafter "PATHWAYS TO DEEP DECARBONIZATION"].

[2] Nat'l Renewable Energy Laboraty, *Renewable Electricity Futures Study* (2012), Executive Summary, at 30 (estimating electricity demand could be met by 80% renewable sources by 2050), at http://www.nrel.gov/docs/fy13osti/52409-ES.pdf.

reliance on significant amounts of new natural gas power generation,[3] a potential major transition away from traditional base load power plants,[4] significant investment in distributed generation and new technologies,[5] and increased focus on demand-side measures.[6] But given the industry's stationary capital assets with financial and operational lives ranging from 50-80 years in length, energy infrastructure can change only at a slow pace. Path dependency threatens "carbon lock-in," which could thwart any successful transition to a low carbon energy system.[7] To the extent that grid decarbonization adversely affects the economic value of a significant portion of current assets (such as older coal plants), some industry investors and analysts have even raised concerns that the impending disruptions of change could lead to financial distress, hardship and, at the extreme, catastrophe.[8]

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[3] *Cf*. Steve Weissman, *Natural Gas as a Bridge Fuel: Measuring the Bridge*, CTR. FOR SUSTAINABLE ENERGY 1 (Mar. 2016) (noting near-term need but cautioning against long-term natural gas reliance).
[4] *See* LUCY JOHNSTON & RACHEL WILSON, STRATEGIES FOR DECARBONIZING THE ELECTRIC POWER SUPPLY 6-7 (Regulatory Assistance Project 2012), online at https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=9&cad=rja&uact=8&ved=0ahUKEwjk6f-Mv6jNAhVPc1IKHUawDPUQFghTMAg&url=http%3A%2F%2Fwww.raponline.org%2Fdocument%2Fdownload%2Fid%2F259&usg=AFQjCNGKA2nczeApiKKNrN-HxCF31v_7XA&sig2=W1gP-7C5Z_mfvQpxFYXBVw&bvm=bv.124272578,d.aXo (noting that more than 70 percent of U.S. coal-fired capacity is more than 30 years old).
[5] *See, e.g*., Amy L. Stein, *Distributed Reliability*, 87 U. COLO. L. REV. 887 (2016) (considering regulatory needs for incorporating distributed generation into grid reliability policymaking); Amy L. Stein, *Reconsidering Regulatory Uncertainty: Making a Case for Energy Storage*, 41 FLA. ST. U. L. REV. 697 (2014) (considering regulatory needs for emerging technologies like energy storage).
[6] *See* PATHWAYS TO DEEP DECARBONIZATION, *supra* note 1.
[7] As Gregory Unruh describes:

> . . . . industrial economies have been locked into fossil-fuel based energy systems through a process of technological and institutional co-evolution driven by path-dependent increasing returns to scale. It is asserted that this condition, termed carbon lock-in, creatsed persistent market and policy failure that can inhibit the diffusion of carbon-saving technologies despite their apparent environmental and economic advantages.

Gregory Unruh, *Understanding Carbon Lock-In*, 28 ENERGY POL'Y 817, 817 (2000).
[8] *See, e.g.,* Elisabeth Grarry & Steven Kihm, *Does Disruptive Competition Mean a Death Spiral for Electric Utilities?*, 35 ENERGY L.J. 2 (2014); DELOITTE, THE NEW MATH: SOLVING THE EQUATION FOR DISRUPTION TO THE U.S. ELECTRIC POWER SECTOR (2013), at http://www2.deloitte.com/content/dam/Deloitte/us/Documents/energy-resources/us-energyandresources-the-new-math.pdf; EDISON ELECTRIC INSTITUTE, DISRUPTIVE CHALLENGES: FINANCIAL IMPLICATIONS AND STRATEGIC RESPONSES TO A CHANGING RETAIL ELECTRIC BUSINESS (January 2013),2013), at http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf. *See also* Alex Morales, *"Stranded Assets:" Will Efforts to Counter Warming Render Energy Reserves Worthless?,* WASHINGTON POST, Dec. 5, 2014, at https://www.washingtonpost.com/business/stranded-assets-will-efforts-to-counter-warming-render-energy-reserves-worthless/2014/12/05/ecbc73a6-7a45-11e4-9a27-6fdbc612bff8_story.html (describing a similar threat to the fossil fuel industry more generally). To underscore the significant of stranding impacts of the impending transition, one study envisions that the global stranded cost impact of the impending transition is in the range of $25 trillion for the entire energy sector. *See* DAVID NELSON, ET AL., MOVING TO LOW-CARBON ECONOMY: THE IMPACT OF POLICY PATHWAYS ON FOSSIL FUEL; ASSET VALUES iv (Climate Policy Initative 2014), at http://climatepolicyinitiative.org/wp-content/uploads/2014/10/Moving-to-a-Low-Carbon-Economy-The-Impacts-of-Policy-Pathways-on-Fossil-Fuel-Asset-Values.pdf.

Energy law can deal with such change. On many occasions over the past half century, energy law has been required to confront the "stranded costs" of transitions—that is, the value of a regulated firm's investments left shipwrecked by changing regulatory circumstances. From an accounting standpoint, stranded costs are defined as the difference between an asset's book value—including such things as power generating equipment—and its market value.[9] From a regulatory compact standpoint (discussed in more detail momentarily), stranded costs are those investments that a utility has incurred to meet its obligations to serve customers with an expectation of cost recovery through rates, but which may no longer be recoverable due to a change in the rules or new market competition in the industry.[10] Our initial working definition of stranded costs is simple: We focus on existing energy infrastructure that retains some useful life but that can no longer generate initially expected revenue due to regulatory shifts, market forces, or innovation. But as we also discuss, in the transition to decarbonization the stranded cost issue will be just as significant for new investments in energy resources as it is for existing infrastructure.

This Article maintains that the traditional approach energy regulators have used to compensate stranded costs for existing resources during industry transitions has suffered from myopia and must be reformed to address the transition to decarbonization. The traditional notion of stranded costs is embedded in an understanding of regulation known as the "regulatory compact (or contract),"[11] where the utility takes on an obligation to serve customers and, in return, is guaranteed an opportunity to recover the costs of its investments. This approach worked for decades to provide *some* degree of certainty to investors, though its flaws are also well known.[12] In addressing new stranded cost challenges and opportunities, energy law can best facilitate a balance between promoting investor certainty and providing flexibility by being proactive, recognizing that past approaches to stranded cost recovery could just as easily thwart as facilitate decarbonization.

This Article proceeds as follows. Part I argues that stranded cost recovery mechanisms over the past 50 years have fixated on honoring the "deal" of the regulatory contract for incumbent firms and their investors. Furthermore, regulators have seriously grappled with transition costs issues only after a change in conditions has occurred. Each time a new energy transition takes place, energy regulators have provided for significant stranded cost compensation, though it is not always clear that the manner in which they did so provided sound investment signals for the energy system. Moreover, stranded cost

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[9] Charles Stalon, *Stranded Investment Costs: Desirable and Less Desirable Solutions*, in Proceedings: What are the Transition Costs to a More Competitive Market and Who Should Pay?, at 2 (June 15, 1994).
[10] William J. Baumol & J. Gregory Sidak, *Stranded Costs*, 18 HARV. J. L. & PUB. Pol'y 835, 835 (1995).
[11] *See* Jersey Century Power & Light Co. v. FERC, 810 F.2d 1168, 1188 (D.C. Cir. 1987) (Starr, J., conc.) (referencing the term).
[12] Particularly salient examples include the numerous canceled nuclear and coal-fired power plants in the 1980s and the major shifts associated with moving to competitive electricity markets. *See, e.g.*, John Burrett McArthur, *Cost Responsibility or Regulatory Indulgence for Electricity's Stranded Costs?*, 47 AM. U. L. REV. 775 (1998) (electricity restructuring); Richard J. Pierce, Jr., *Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity*, 132 U. PA. L. REV. 497 (1984) (coal and nuclear). See *infra* at Part I.A for further discussion.

recovery has often stood in the way of change, failing to sufficiently address the "stranded benefits" of new transitions[13] or the broader social values advanced by industry transitions. In large part this has happened because stranded cost recovery has been addressed only ex post, when a fixation on losses to a firm's existing investments drives the discussion. We maintain that this stranded cost myopia has distorted some basic investments signals, magnified an excess capacity problem with some base load power generation facilities, thwarted new entrants, and prolonged the energy sector's dependency on existing energy infrastructure, including many fossil fuel plants.

Part II turns to the energy sector's transition to decarbonization. The transition to a new, low-carbon normal challenges every part of this sector, including resource extraction, power generation, transmission, and distribution. Given regulators' past appetite for stranded cost compensation, we can expect incumbent firms to raise new calls for stranded cost compensation each time a new change is proposed.[14] Even now, several coal companies have already filed for bankruptcy, some nuclear power plants are at risk for early closure, and local utilities are fighting rooftop solar incentives such as net metering.[15] At the same time, policymakers and industry representatives often speak of natural gas, and increasingly, nuclear power, as bridge fuels that will facilitate the transition to a low carbon future.[16] The simple reality is that energy regulation is not particularly adept at "temporary"—and once approved, incumbent firms expect their assets to stay in operation and produce revenue as long as they can convince regulators to allow it. At the very minimum, if left unaddressed these stranded cost issues threaten to delay the transition to decarbonization.

As discussed in Part III, the transition to decarbonization requires regulators to address stranded costs, though to avoid carbon lock-in they must apply similar principles to both new and old energy infrastructure. Even so, as Part III also discusses, this does not necessarily mean the end of stranded cost recovery with a transition towards decarbonization. Rather, we expect stranded cost issues to be as important as ever. Investors will continue to seek some commitment from the regulatory process before

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13 "Stranded benefits," arethose offsetting benefits that transitions can create for firms in an industry or their investors. *See infra*, Part I.B.2.

14 See, e.g., Jim Chen, *The Nature of the Public Utility: Infrastructure, the Market, and the Law*, 98 NW. U. L. REV. 1617, 1700 (2004) (reviewing GOSE A. GOMEZ-IBANEZ, REGULATING INFRASTRUCTURE: MONOPOLY, CONTRACTS, AND DISCRETION (2003)); William J. Baumol & J. Gregory Sidak, *The Pig in the Python: Is Lumpy Capacity Investment Used and Useful?*, 23 ENERGY L.J. 383 (2002).

15 *See* Richard Martin, *Battles Over Net Metering Cloud the Future of Rooftop Solar*, MIT TECH. REV. (Jan. 5, 2016), at https://www.technologyreview.com/s/545146/battles-over-net-metering-cloud-the-future-of-rooftop-solar/ (describing several such challenges).

16 Weissman, *supra* note 3, at 1; ***see also*** N.Y. Pub. Serv. Comm'n, Order Adopting A Clean Energy Standard, Nos. 15-E-0302 & 16-E-0270, at 1 (Aug. 1, 2016) (listing among purposes of new clean energy standard "to preserve existing zero-emissions nuclear generation resources as a bridge to the clean energy future"). New York has approved a Clean Energy Standard, that, among other things, seeks to maintain its nuclear fleet as the state transitions to a low-carbon future, in which it aims for 50% non-emitting electricity by 2050. *See* Denis Grab & Burcin Unel, *New York's Clean Energy Standard Is a Key Step Toward Pricing Carbon Fairly*, UTILITY DIVE, Aug. 18, 2016, at http://www.utilitydive.com/news/new-yorks-clean-energy-standard-is-a-key-step-toward-pricing-carbon-pollut/424741/.

moving forward,[17] and each successive capital investment decision in new energy infrastructure will represent an irreversible choice for decades into the future. But these concerns need not necessitate a wholesale reconstruction of energy law. Rather, we think that the transition to a post-carbon energy sector presents regulators an opportunity to draw from some of energy law's traditional tools to better approach risk compensation—encouraging a more adaptive and flexible grid than in the past, while also attracting new investment by addressing stranded costs proactively in ways that recognize both market and non-market values.

Moving forward, a presumption in favor of stranded cost compensation based on the fact of past stranded compensation could be counterproductive, delaying and frustrating the transition towards decarbonization. But realistically, some stranded cost compensation will be essential to the decarbonization transition. If approached in a careful manner, stranded cost recovery can facilitate a transition toward decarbonization by encouraging investors and firms to better price the core market and non-market attributes of energy resources. In order to do so, regulators need to pay attention to the timing of cost allocation, avoiding the temptation to address stranded costs only at the back end of the carbon transition. For example, as discussed in more detail below, regulators making decisions regarding major new infrastructure projects like pipelines and transmission lines should be attentive to stranded cost issues before approving projects, instead of waiting to address stranded costs only after change has occurred.[18]

Regulators providing for stranded cost recovery must also be attentive to social values that are not currently priced in energy markets. Changes associated with decarbonization present a particularly propitious opportunity for regulators to address important values such as reliability and carbon impacts of various energy resources in stranded cost compensation, especially where the competitive energy markets fail to price these features of energy resources.[19] This Article proposes some ways for stranded cost recovery to better recognize these positive benefits associated with regulatory transitions for new energy resources, without conflicting with federal energy market policy.

Reforms that address regulatory risk through early stranded cost recovery will inevitably come at some cost to consumers in the near term, yet a return on investment is imperative to attracting capital for new infrastructure that will facilitate a balanced portfolio of energy resources for a decarbonized grid.[20] If stranded costs for both new and old resources are addressed with similar principles in mind, we believe that the net

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[17] Eliminating such commitments altogether would likely drive up the overall cost of capital for regulated utilities. *See* Emily Hammond & Richard J. Pierce, Jr., *The Clean Power Plan: Testing the Limits of Administrative Law and the Electric Grid*, 7 GEO.W. J. ENERGY & ENVTL. L. 1 (2016).
[18] *See infra* Part III.B.1.
[19] For discussion of the general issue, see Emily Hammond & David B. Spence, *The Regulatory Contract in the Marketplace*, 69 VAND. L. REV. 141 (2016).
[20] Low returns available to investors are often seen as a barrier to attracting the investment necessary to decarbonize the electric power sector. *See, e.g.,* WORLD ECONOMIC FORUM, THE FUTURE OF ELECTRICITY: ATTRACTING INVESTMENT TO BUILD TOMORROW'S ELECTRICITY SECTOR (2015), at http://www3.weforum.org/docs/WEFUSA_FutureOfElectricity_Report2015.pdf.

effect will be to reduce the overall cost of capital related to investment in a decarbonized energy system.

I. Energy Law's Stranded Cost History

Over the past half century, the energy sector has undergone some remarkable transformations. The regulatory contract that has predominated energy law's history envisions a utility taking on customer service obligations in exchange for a guarantee that its investors will be compensated for risk.[21] Even with traditional rate regulation, changing economic conditions, technological obsolescence, and unexpected shifts in regulatory approach have presented a threat to investors in energy firms.[22] Specifically, investors have faced a risk that an energy utility's investments would be rendered stranded as a result of transitions. If energy law did not find ways to compensate investors for stranded costs, this could adversely affect the overall cost of capital for new infrastructure, requiring firms to incur higher interest rates to attract debt and equity investors.

Over the past half century, the energy industry has undergone three important stranded cost experiments: disallowance of construction costs for canceled nuclear power plants in the 1980s;[23] "take-or-pay" natural gas supply contracts associated with open access in gas pipelines;[24] and stranded power generation assets associated with a transition to competitive electric power markets.[25] As described in more detail below, in each of these scenarios significant amounts of economic capital were threatened by transition. As each transition took place, energy investors (and utilities) made forecasts of major economic loss and, at the extreme, financial catastrophe. In most instances, regulators drew on tools (often with controversy) to mitigate adverse financial impacts associated with impending transition. By deferring any focus on compensating investors for the risks of change to the future, regulators in the past were able to keep the cost of new capital for energy firms low, although once chonge was imminent the focus shifted to stranded cost compensation as a way to address these risks ex post.

Despite some industry prognostications, the sky never did fall with past energy industry transitions. But that also does not mean that stranded cost compensation always

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21 *See* Hammond & Spence, *supra* note [22], at 149-51 (describing traditional regulation).

22 *E.g.*, Pierce, *supra* note [12] .

23 Though less frequently mentioned, this issue extended to coal-fired plants as well. *See* Pierce, *Regulatory Treatment of Mistakes in Retrospect*, *supra* note [12] (documenting both nuclear and coal-fired plant cancellations).

24 *E.g.*, Holly C. Doane, *Take-Or-Pay: FERC's Regulatory Dilemma*, 2 Spg. Natural Res. & Env't 18, 18 (1987) ("No other issue in the history of the Federal Energy Regulatory Commission (FERC) has caused such paralysis . . . .").

25 *See* Jim Rossi, *The Electric Deregulation Fiasco: Looking Toward Regulatory Federalism to Promote a Balance Between Markets and the Provision of Public Goods*, 100 MICH. L. REV. 1768, 1778-79 & n.25 (describing stranded cost recovery associated with California deregulation and collecting criticisms).

produced good results. In the past, regulators consistently favored stranded cost compensation ex post—that is, after projects (and their expected investments costs) had been approved, and sometimes decades after assets had been constructed and used to produce and deliver energy. By only really addressing the issue of stranded costs *after* initial investment decisions have been made, many regulators based stranded cost calculations on perceived investor losses related to a large-scale, already-approved capital asset. This ex post environment for determining stranded costs invited industry stakeholders to present regulators with grossly exaggerated claims of the adverse impact of a transition on the firm's investors, and to present little or no evidence of how change would produce benefits for the firm or others. This approach to stranded cost compensation may have assuaged regulators, firms, and their investors, but it resulted in a myopia that exaggerated stranded costs losses to investors, delayed regulatory change, and ignored any broader assessment of the social costs and benefits associated with transitioning. Regulators determining stranded costs in this manner did a poor job of separating the ordinary economic and technological risks that any business investor would expect, from regulatory risks over which firms have little or no control.

A. Past Stranded Cost Experiments

As should be evident, discussions of stranded costs in the energy industry are hardly new. Threats to investor expectations due to new technologies or changing economic conditions have a long legacy in regulated industries. For example, the impact of new technologies and new market entrants was at the core of the dispute of the landmark Charles River Bridge case, which clarified principles surrounding monopoly and innovation prior to industrial development.[26] In deciding that important case 180 years ago, the Supreme Court endorsed the principle that a monopoly's charter should be interpreted narrowly to favor new entrants.[27] Yet stranded cost compensation experiments over the past 50 years in the energy industry seem to run against the grain of this longstanding principle, with regulators consistently finding ways to ensure that investor-backed expectations are not upset by industry changes. As these experiments show, instead of being wary of stranded costs, regulators have shown a considerable appetite for compensating investors post hoc, routinely approving customer charges designed to guarantee an incumbent energy utility 100% compensation for stranded costs during regulatory, economic and technological transitions in the energy sector.

1. Excess Capacity and Canceled Nuclear Power Plants

One high profile stranded cost issue was associated with new nuclear power plants—many of which were canceled mid-construction—and the subsequent disallowance of cost recovery by regulatory commissions in the 1970s and 80s.[28] In the late 1960s and early 1970s, nuclear power looked like a prudent investment: electricity

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[26] The Proprietors of the Charles River Bridge v. the Proprietors of the Warren Bridge, 36 U.S. 420 (1837).
[27] *Id*. For discussion see STANLEY I. KUTLER, PRIVILEGE AND CREATIVE DESTRUCTION: THE CHARLES RIVER BRIDGE CASE (1971).
[28] *See* EISEN ET AL., ENERGY, ECONOMICS AND THE ENVIRONMENT 400-02 (4^{th} ed. 2015) (describing changes in the nuclear energy sector over time).

demand was projected to sharply increase, and nuclear power (and coal) appeared to be a far better investment than oil- and gas-fired plants.[29] Not only was nuclear power projected to be less costly to operate, but natural gas was in very short supply, and the United States had national security concerns about relying on foreign oil.[30] But by the late 1970s and into the 1980s, things changed. Demand did not increase as expected, Three Mile Island prompted concerns about the safety of nuclear power, and both world oil and the domestic natural gas markets underwent substantial price reductions. Utilities were left holding excess generating capacity, and it became clear that newer power generation technologies could produce power more cheaply than nuclear plants. Over 120 partially constructed plants were canceled, and the question of how to address the resulting stranded costs loomed large.[31]

In the end, many of these plants received full or at least partial cost recovery. As Richard Pierce describes it, the policy effect of the regulatory response was to provide many private utilities compensation for what, in retrospect, were considered mistakes—perhaps in part because the regulatory process encouraged investment in large base load power generation plants.[32] Forcing the utilities to bear the full costs of cancelations would have ignored this regulatory relationship and, moreover, would serve to increase the overall cost of capital associated with these investments, perhaps putting the utility out of business.[33] On the other hand, allowing full cost recovery for every loss a firm would incur due to mistaken investment decisions would unfairly burden customers—making it politically untenable and significantly diverging from how a competitive market would approach investment risks.[34]

Some jurisdictions famously did not allow for stranded cost recovery at all. In the landmark decision *Duquesne Light Co. v. Barasch*,[35] for example, the Supreme Court rejected a Takings Clause challenge brought by the owners of canceled nuclear power plants that had been denied cost recovery for investments that had been deemed prudent when they were initially made.[36] More often, however, state commissions allowed nuclear power companies to recover from customers at least some of their stranded costs,

[29] Pierce, *Regulatory Treatment of Mistakes in Retrospect. supra* note [12] at 500-01.
[30] *Id*.
[31] EISEN ET AL., *supra* note [31], at 401.
[32] *See* Pierce, *Regulatory Treatment of Mistakes in Retrospect, supra* note [12].
[33] *See* Legislative Utility Consumers' Council v. Public Service Co. of New Hampshire, 402 A.2d 626 (N.H. 1979) (describing financial struggles of utility undertaking nuclear power plant construction).
[34] Pierce, *Regulatory Treatment of Mistakes in Retrospect*, *supra* note [12], at 506.
[35] 488 U.S. 299 (1989).
[36] *Id*. at 302-03. Though the Court was not receptive to utilities' claim that the Constitution requires stranded cost recovery for cancelled nuclear plants, it also did not dismiss the idea that the Constitution provides a floor to protect investor-based expectations. At the extreme, the Court noted, a rate still could be so low that it is confiscatory, especially if a firm is not allowed to compensate its investors at all for the financial risks that they incur. Id. at 315 (citing FPC v. Hope Natural Gas Co., 320 U.S., 591 602 (1944) ("[R]eturn to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.")). In addition, a regulator cannot "arbitrarily switch back and forth between methodologies in a way which required investors to bear the risks of bad investments at some times while denying them the benefits of good investments at others . . . ." *Id*. at 315.

whether these were attributed to excess capacity or for canceled plants.[37] And a few plants under construction during this time were permitted to recover from customers for construction works in progress (CWIP), representing regulators' recognition of the uncertain economic and regulatory environment for new nuclear plants and the need for substantial lines of credit early in the construction phase.[38]

Significantly, canceled nuclear plants were not a transition cost that regulators or investors had accurately predicted at the time that plants were approved in the first place. Rather, these stranded cost recovery decisions were routinely made *after* plants had undergone "prudency" review (the reasonableness review rate regulators apply to new investments) and were approved for construction. Still, routine ex post stranded cost recovery, independent of the initial decision of the firm (and its investors) to incur the costs of nuclear power generation facilities, could have an undeniable impact on the cost of capital and investment decisions. If, at the time of making investment decisions, investors had routinely expected this kind of ex post compensation (and perhaps the regulatory contract encouraged them to do so), the initial cost of capital for a regulated utility would be lower than that of a competitive firm because utility regulators (and the regulatory contract) effectively insured the risk of change for private investors. Against the backdrop of rate regulation, this artificially low cost of capital could have encouraged overinvestment in large "base load" plants (i.e., those that must run at or near their full capacity to meet customer load, typically nuclear and coal plants), contributing even further to excess capacity. On the other hand, if no compensation for harms caused by regulatory change was expected by investors ex ante (i.e., at the time of the initial investment in the firm), investors would demand a risk premium (and a higher return on investment) to insure themselves against the possibility of change, so without stranded cost recovery the firm's cost of capital would need to be priced higher to reflect this risk. A higher cost of capital would have discouraged new investments in these assets, given that regulators were attentive to the cost of capital in approving new investments and setting utility rates, so some stranded cost recovery provided regulators a delicate way of balancing a need for investor certainty to attract capital with regulators need to keep the cost of capital for new infrastructure as low as possible, to minimize the immediate impacts of new infrastructure on customer rates.

2. Natural Gas Pipelines and Take-Or-Pay Contracts

A second stranded cost recovery experiment from the past half-century is associated with the Federal Energy Regulatory Commission's (FERC) implementation of open access in natural gas pipelines to encourage competition in interstate gas supply markets. Congress began restructuring the natural gas industry in the late 1980s by

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[37] Examples are detailed throughout Pierce, *Regulatory Treatent of Mistakes in Retrospect*, *supra* note [12] .

[38] *E.g.*, Legislative Utility Consumers' Council v. Public Service Co. of New Hampshire, 402 A.2d 626 (N.H. 1979) (upholding state commission's authority to allow construction funds for Seabrook nuclear plant to be recovered in CWIP); *cf.* Jersey Central Power & Light Co. v. FERC, 810 F.2d 1168, 1185-86 (D.C. Cir. 1987) (noting that FERC might permissibly allow utilities to include some unamortized costs of canceled plants in rate base).

unbundling gas sales from pipeline transportation services and providing equal access to the latter.[39] This approach recognized that traditional gas regulation's approach to setting single rate for pipeline gas had failed to see that there are two or more distinct markets bundled together, only one of which is a natural monopoly (i.e., the "pipes"). FERC set out to "unbundle" these distinct markets, implementing an "open access" regulatory scheme that applies only to the natural monopoly market so that all producers had comparable access to the pipelines to ship their gas to the buyer who offers them the best deal.[40]

However, pipelines' stranded costs presented a barrier to the transition to this new competitive market.[41] In order to support pipeline construction and operation, many pipelines had committed billions of dollars in long-term "take-or-pay" contracts at very high prices. These contracts obligated pipelines to pay suppliers, even when pipelines could not take the gas.[42] In initially addressing the transition to pipeline deregulation, FERC refused to grant pipeline requests for take-or-pay relief.[43] FERC's Order 436,[44] described by the D.C. Circuit as a "complete restructuring" of the industry,[45] did not provide for any take-or-pay compensation because pipelines were successfully negotiating themselves out of these obligations without FERC's assistance.[46] But the S.C. Circuit vacated Order 436, accusing FERC of "blindness" to the impacts of open access on pipelines, as well as a "tendency to elevate into affirmative benefits what are at best palliatives."[47] Without tangible take-or-pay contract relief, the D.C. Circuit likened the voluntary open access option FERC had provided pipelines to "the choice between the noose and the firing squad."[48] When FERC continued to refuse any compensation for take-or-pay contracts on remand, the D.C. Circuit again rejected the agency's approach, charging FERC with attempting to delay indefinitely until the issue went away.[49]

FERC addressed the issue in Order 500, which adopted an equitable splitting of take-or-pay costs.[50] As FERC stated there:

> The Commission recognizes that it is difficult to assign blame for the pipeline industry's take-or-pay problems. In brief, no one segment of the natural gas industry or particular circumstance appears wholly responsible for the

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[39] *See generally* Richard J. Pierce, Jr., *Reconstituting the Natural Gas Industry from Wellhead to Burnertip,* 9 ENERGY L. J. 1 (1988).
[40] *Id.*
[41] For discussion, see Donald F. Santa, Jr. & Clifford S. Sikora, *Open Access and Transition Costs: Will the Electric Industry Transition Track the Natural Gas Industry Restructuring?*, 15 ENERGY L.J. 273 (1994).
[42] For an overview, see EISEN ET AL., *supra* note [31].
[43] Order 380, 49 Fed. Reg. at 22,779, 22, 282 (1984).
[44] Order 436, 50 Fed. Reg. 42,408 (1985).
[45] Associated Gas Distrib. v. FERC, 824 F.2d 981, 993 (D.C. Cir. 1987) ("AGD I")
[46] *Id*. at 1023.
[47] *Id*. at 1025.
[48] *Id*. at 1024.
[49] Am. Gas Ass'n v. FERC, 888 F.2d 136, 142 (D.C. Cir. 1989).
[50] Order 500, 52 Fed. Reg. at 30,334 (1987).

> pipelines' excess inventories of gas. As a result, all segments should shoulder some of the burden of resolving the problem.[51]

In Order 500, FERC still failed to endorse full recovery of pipeline stranded costs, perhaps because the very existence of these take-or-pay contracts indicated that pipelines were aware of some risks of changing economic conditions. In Order 636, the order that completed FERC's gas pipeline restructuring, FERC finally allowed pipelines to bill customers for 100% of their remaining stranded costs,[52] though the agency was also careful to note that the equitable sharing approach of the past (as endorsed in Order 500) had been necessary to "encourage pipelines to share some of the cost of the extraordinary take-or-pay liabilities of the early and mid-1980s."[53] Although the D.C. Circuit had made it clear that FERC could not completely ignore the impact on investors of take-or-pay contracts during pipeline market restructuring, it bears emphasis that the agency was never legally obligated to provide 100% recovery for stranded costs associated with transitioning from regulated to competitive gas markets—even though Order 636 ultimately took this policy position.

The nature of the stranded costs incurred by pipelines during this transition differed from nuclear stranded costs. Fuel costs are a relatively small component of the costs of operating a nuclear power plant, so nuclear stranded cost compensation debates were driven by the fixed costs of the assets. By contrast, given how pipeline contracts were executed in the industry, pipelines' claims to stranded costs were driven almost entirely by the volatility in gas markets. The use of stranded cost recovery to compensate firms for this risk made it even more difficult for regulators to assess which risks were appropriate for investors, on the one hand, as opposed to consumers, on the other. Still, as with nuclear power plants, stranded cost recover for take-or-pay contracts was approved post hoc, after these contracts were executed, so this was not a risk that pipeline investors were presumably compensated for in their initial return on investment. Ex post stranded cost recovery helped to keep the cost of capital for approved pipeline projects low, while also providing investors compensation for risks of change as they materialized, rather than in a higher return on their initial investment.

3. Competitive Restructuring of the Electric Power Industry

A third and more recent experiment with stranded cost recovery relates to competitive restructuring of the electric power industry in the 1990s. For most of the twentieth century, the electric utility had been regulated as a natural monopoly, but a range of reforms in the 1970s and 80s led to efforts to restructure the industry towards competitive markets, much in the manner that FERC had reformed natural gas markets.[54]

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[51] Order 500, 52 Fed. Reg. at 30,337.
[52] Order 636, 57 Fed. Fed. 13,267 (Apr. 16, 1992).
[53] *Id*. at 13,308.
[54] *See* Richard J. Pierce, Jr., *The State of the Transition to Competitive Markets in Natural Gas and Electricity*, 15 ENERGY L.J. 323 (1994).

This transition revived a concern about constitutional takings of the sort that pepper the history of energy law,[55] repackaged for this particular set of events as "deregulatory takings."[56] These stranded cost claims included requests to allow regulatory compensation for some power plant assets that were no longer considered valuable in competitive power markets, in a similar manner to canceled nuclear plants.[57] However, many firms' claims to stranded cost from electric power restructuring also related to lost expected income given the change in regulatory rules. Just as with gas pipeline stranded cost compensation, this kind of focus on income streams stranded by regulatory transition challenged the ability of regulators to separate ordinary business risks over which the firm (and its investors) have some degree of control, from regulatory risks associated with the transition to competitive electric power markets.[58] Estimates of utilities' stranded costs in the transition to competitive electric power markets ranged from $10 billion to $500 billion, with most estimates falling in the $100 billion to $200 billion range.[59]

As with nuclear power plants' stranded cost recovery, courts were not receptive to legal claims that the Constitution required full compensation for all revenue lost during a transition to a competitive electricity market.[60] However, despite a lack of any judicial mandate to provide for full stranded cost compensation, regulators routinely found ways to help mitigate the stranded cost impacts on firms and investors of the regulatory transition to competitive markets. In Order 888, issued in 1996, FERC adopted an open access regime for wholesale electric power supply, similar to its competitive market approach for natural gas.[61] In contrast to FERC's initial shared cost allocation for take-or-pay contracts,[62] FERC allowed utility shareholders to recover 100% of the stranded costs associated with transitioning to a competitive wholesale power supply industry.[63] In adopting retail competition plans, states such as California also allowed for full stranded cost recovery.[64] Importantly, however, some states transitioning to competitive retail

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[55] *E.g.*, Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989) (takings challenge regarding cost recovery for canceled nuclear power plants); Fed. Power Comm'n v. Hope Natural Gas, 320 U.S. 591 (1944) (takings challenge for method of computing cost recovery).

[56] J. GREGORY SIDAK & DANIEL F. SPULBER, DEREGULATORY TAKINGS AND THE REGULATORY CONTRACT (1997).

[57] *Id.*

[58] *Cf.* Jim Rossi, *The Irony of Deregulatory Takings*, 77 TEX. L. REV. 297, 307 (1998) (reviewing J. GREGORY SIDAK & DANIEL F. SPULBER, DEREGULATORY TAKINGS AND THE REGULATORY CONTRACT: THE COMPETITIVE TRANSFORMATION OF NETWORK INDUSTRIES IN THE UNITED STATES (1997))

[59] *See* CBO PAPER, ELECTRIC UTILITIES: DEREGULATION AND STRANDED COSTS 15 (Oct. 1998).

[60] As is discussed in John Burritt McArthur, *The Irreconcilable Difference Between FERC's Natural Gas and Electricity Stranded Cost Treatments*, 46 BUFF. L. REV. 71 (1998); Susan Rose-Ackerman & Jim Rossi, *Disentangling Deregulatory Takings*, 86 VA. L. REV. 1435 (2000).

[61] Order 888, 61 Fed. Reg. 21,540 (1996).

[62] McArthur, *supra* note 60.

[63] *Id*. at 93.

[64] *Infra* note 65.

power markets refused to allow for the full recovery of stranded costs or denied them altogether.[65]

B. Stranded Cost Myopia

These past experiments with stranded cost recovery and the tools used by regulators to address them share some common characteristics that contributed to a blinkered regulatory perspective, distorting the cost of capital to consistently favor old energy infrastructure over new entrants and new projects. Importantly, they were not driven by judicial mandate[66] so much as by political and regulatory processes that invited utilities (and their investors) to invest resources in lobbying for compensation for the stranded costs associated with industry changes, typically in the form of additional charges that customers would pay in their future bills. While this approach to stranded cost compensation was designed to ensure that the firm would be able to continue to attract capital at a low cost to customers, it also served to lock in the status quo, resulting in delays in industry transitions, including slowing the onset of new technologies.[67] The narrowly focused nature of these past experiments related to both the timing of stranded cost recovery, and a regulatory lack of appreciation for values beyond the immediate adverse financial impact of transitions on investors.

1. Ex Post Recovery Mechanisms

As we have described, a common feature of these past experiments with stranded cost compensation is an appetite, on the part of both regulators and firms, for transition cost recovery at the back end of investment decisions. These past examples do not illustrate a regulatory process that makes a concerted effort to address stranded costs before investment decisions are made or at the time of their initial approval. Hindsight is always 20/20, so such ex post recovery of stranded costs serves to avert acknowledgement of any past mistakes on the part of regulators or firms. On the other hand, providing compensation for investment decisions gone wrong only ex post can look more like a form of industry bailout than traditional cost-based decisionmaking, which would encourage actors to price any risk of change into their initial investment decisions.

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[65] California allowed for 100% stranded cost recovery in its retail market transition; other states, by contrast, provided for only partial stranded cost recovery or were outright hostile to stranded cost recovery claims, forcing firms to take the initiative in selling off uneconomic assets. For discussion, see Elizabeth A. Nowicki, *Denial of Regulatory Assistance in Stranded Cost Recovery in a Deregulated Electricity Industry*, 32 LOY.-L.A. L. REV. 431, 442-43 (1999).

[66] *See* Rossi, supra note [28], at 307 (noting that since *Market Street Railway v. Railroad Comm'n*, 324 U.S 548 (1945), "courts have consistently imposed on regulated firms the risk of changing technological and economic circumstances.").

[67] This, of course, was one of the concerns famously raised by the Proprietors of the Charles River Bridge and rejected by Chief Justice Taney's majority, which reasoned that the loss of profit from the construction of a new bridge was simply irrelevant to determining the state's contractual obligations surrounding a monopoly charter, especially where the public stood to benefit from new technology. The Proprietors of the Charles River Bridge v. the Proprietors of the Warren Bridge, 36 U.S. 420, 544 (1837) (noting any "ambiguity in the terms of the [regulatory] contract must operate against [the private company] and in favor of the public").

These experiments show that stranded cost compensation helped to routinely ensure that investor risks were not ignored. As described above, however, this practice could contribute to an artificially low initial cost of capital for new investments. If regulators themselves were insuring against regulatory change, investors (and the firm) had no incentive to demand a return on investment that prices the risks of regulatory change in present value as new infrastructure investment decisions were made. As Richard Pierce has chronicled, for example, with respect to the stranded cost problems associated with excess nuclear capacity, the regulatory tools used to address those problems exacerbated the problem, arguably encouraging rate-regulated utilities to overinvest in certain forms of power supply.[68]

At the same time, energy law's historic appetite for back-end cost recovery with changing circumstances systematically encouraged firms to lobby against regulatory change and, once changed seemed imminent, to make inflated claims for stranded cost recovery. To take one example, with impending competitive restructuring of the electric power industry, the industry claimed that stranded costs would be in the hundreds of billions, and that restructuring would potentially force many utilities into bankruptcy.[69] Not every firm made substantial profits in the transition to competitive markets, but today it is recognized that the actual stranded costs incurred by firms were far less—closer to $10 billion—even though the regulatory and legislative process provided for transition recovery in excess of $100 billion.[70] Addressing stranded costs after an investment decision is more likely to lead to systematic overcompensation for regulatory risk because of loss aversion, or the exaggerated value a firm (especially a regulated firm with long-lived, capital intensive assets) might place on losing revenue streams they have received in the past.[71] Out of fear of seeing their past investments lose existing revenue, many energy firms and their investors routinely overstated their stranded cost losses.[72] Regulators too feared criticism for past decisions they made, and therefore were often complicit in approving stranded cost recovery for energy infrastructure that they approved or encouraged. The expectation that regulators would provide a back-end bailout—as happened with excess nuclear capacity, take-or-pay-contracts, and competitive restructuring—encouraged firms to aggressively use the regulatory process to further prolong the revenue streams associated with their assets.[73]

These experiments with stranded cost recovery also show how energy regulators routinely confused different kinds of risk in compensating firms for stranded costs. Risks of economic and technological change were frequently lumped together in discussions of stranded cost recovery, perhaps because the expectation of recovery alleviated any need

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68 Pierce, *Regulatory Treatment of Mistakes in Retrospect*, supra note [12].
69 *See* CBO PAPER, ELECTRIC UTILITIES: DEREGULATION AND STRANDED COSTS 15 (Oct. 1998).
70 Moody's Investors Service, *Special Comment, Smoke, Mirrors & Stranded Costs: How Stranded Cost Estimates Went from North of $130 Billion Dollars to $10 Billion*, at 1 (Oct. 1999). At the time, Moody's estimated that more than $100 billion of this was already "expected to be taken care of. . . via regulatory and legislative processes." *Id*.
71 Eyal Zamir, *Law's Loss Aversion*, *in* THE OXFORD HANDBOOK OF BEHAVIORAL ECONOMICS AND THE LAW ch. 11 (Oxford University Press 2014) (Eyal Zamir & Doron Teichman, eds.).
72 *See* Moody's Investors Service, *supra* note 70.
73 *See* Rossi, *supra* note [28]; Chen, *supra* note [14].

for fine-tuning. As stranded cost compensation shifted from focusing on a specific capital asset (as with nuclear power plants) to focusing on broader investor expectations about issues that were tied to things such as long-term contracts and fuel costs, regulatory risks (over which presumably firms and their investors had little or no control) became muddled with ordinary business risks, over which firms and their investors had some degree of control. The result may have been to encourage a moral hazard problem of sorts, leading to overinvestment in energy infrastructure and more excess capacity: Utility investors could expect some compensation at the back-end not only for risks of regulatory change, but for routine business risks associated with changes in economic and technological conditions as well.[74]

2. Stranded Values of Past Stranded Cost Recovery

In addition to contributing to excess capacity and discouraging private pricing of risk, energy law's past experiments with stranded cost recovery did a poor job of recognizing the private and social gains associated with transitions. A fixation on the regulatory contract focused primarily on harms related to financial impacts to the firm and its investors. Regulators gave little consideration to "stranded benefits," that is, the offsetting advantages that a transition might also present to those firms or investors that were claiming harm.[75] For example, in the transition to competitive electric power markets, after restructuring, many utilities retained transmission lines that would become valuable new profit centers in their future operations.[76] Another such benefit is the value older baseload power plants might provide as a reliability and price hedge when competitive electric power markets presented new volatilities. Such benefits were often ignored or downplayed in stranded cost debates. Indeed, there is some evidence to suggest that firms held back on disclosing their plans to exploit new opportunities with deregulation (and hence any stranded benefits) until regulators had resolved stranded cost compensation.[77]

Moreover, past stranded cost experiments made almost no mention of the broader social costs and benefits associated with a regulatory transition, or its impact on the energy system. Regulators' focus on compensating firm-specific investor value provided for little serious consideration of the social costs associated with industry transitions. An emphasis on the financial impact of stranded investments to investors left little room for regulators to address other values like energy reliability or the environmental attributes of energy resources. Little or no attention was given to the costs imposed on others, such as new entrants or workers. Given the lack of any pricing for environmental externalities, neither was serious attention given to the environmental impact of the utility's investment

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[74] *See* Rose-Ackerman & Rossi, *supra* note 60, at 1486-89.

[75] *See* Reed W. Cearley & Daniel H. Cole, *Stranded Benefits Versus Stranded Costs in Utility Deregulation*, *in* THE ENERGY OF A NATURAL MONOPOLY: DEREGULATION AND COMPETITION IN THE ELECTRIC POWER INDUSTRY (Daniel H. Cole, ed. 2003) (defining stranded benefits as a transfer from ratepayers to investors, as opposed to investors to ratepayers).

[76] *See* Rossi, *The Irony of Deregulatory Takings*, supra note 58, at 313 (suggesting transmission and distribution assets as stranded benefits).

[77] *See* Sanjeev Bhojraj et al., *Voluntary Disclosure in a Multi-Audience Setting: An Empirical Investigation*, 79 ACCOUNTING REV., no. 4, at 921 (Oct. 1, 2004).

decisions. If an investor suffered a financial loss, a stranded cost was considered equally meritorious for compensation, whether it supported the operation of a polluting coal plant or a nuclear plant or pipeline, each of which imposes very different impacts on surrounding communities.[78] A decision to compensate stranded costs meant that a resource would continue to operate into the future, but by prolonging the life of obsolete infrastructure without considering broader social costs and benefits, it also left many non-economic values stranded. In other words, looking at the financial impacts of each energy resource on investors and the firm in isolation for purposes of stranded cost compensation has blinded regulators to considering how cost recovery for particular sources of energy supply has broader system-wide effects on the grid, or the broaded balance of energy resources in the nation's power supply portfolio.

II. Decarbonization's Impending Stranded Investment Threat

Decarbonization of the grid will not come cheap.[79] It stands to be one of the most significant economic transformations our economy has experienced in the last century.[80] To the extent that the stranded costs associated with the transition to decarbonization have never been addressed, this threatens to slow any change, contributing to carbon lock-in in the energy sector[81] and discouraging new investment dollars from flowing to new decarbonized energy infrastructure. As these transitions occur, we can predict that industry (and its investors) will continue to show a reluctance to retire any assets that have remaining useful life, regardless of their environmental attributes or whether those investments are stranded because of regulatory change, market forces, or technological innovation. We can expect these firms to aggressively seek ex post compensation. We also can expect incumbent firms to couch the potential for financial losses with the transition in stranded investment terms, inviting the regulatory process to leave important other values stranded.

Changes to infrastructure are already beginning to happen, leading to these kinds of claims for stranded cost compensation. This observation is perhaps most salient for existing coal plants, many of which are expected to be phased out of operation with the

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78 In part, this was because energy law was considered to be a separate paradigm, entirely separate and distinct from environmental law. For discussion, see Todd S. Aagaard, *Energy-Environment Policy Alignments*, 90 WASH. L. REV. 1517 (2015).

79 The costs of a failure to achieve decarbonization, however, may be far greater. *See* Zero Zone, Inc. v. Dep't of Energy, Nos. 14-2147, 14-2159 & 14-2334, 2016 WL 4177217, at *16 (7th Cir. Aug. 8, 2016) (refusing to hold arbitrary and capricious a DOE cost-benefit analysis that included the social cost of carbon).

80 All of the deep carbonization scenarios see a decline in traditional fossil fuel plant investment of $10 billion. Taking the "mixed" scenario as a starting point, increases in annual electricity generation investments would need to increase $15 billion per year from 2021-30 and over $30 billion per year from 2031-2040. By 2050, the electricity sector would need more than $50 billion per year of incremental investment in electricity generation. A "high renewables" case would require more than $70 billion per year of new generation investments by 2050. JAMES H. WILLIAMS, ET AL., PATHWAYS TO DEEP CARBONIZATION IN THE U.S. 47 (2014), at http://unsdsn.org/wp-content/uploads/2014/09/US-Deep-Decarbonization-Report.pdf.

81 For a description of carbon lock-in, see *supra* note 7. (referencing Unruh)

regulation of carbon emissions, as well as existing nuclear plants.[82] No doubt, some existing infrastructure will no longer be considered valuable as new environmental regulations come into effect and energy markets begin to price carbon emissions into investment decisions. Many existing assets will need to be retired to make room for more efficient and less polluting sources of energy, leading to a major shift in investment in the industry. Equally important, we maintain, is that new investment must simultaneously be pursued to allow decarbonization to succeed—which might include a massive investment in new-generation nuclear plants, combined-cycle natural gas plants, large-scale new solar and wind projects, and the transportation infrastructure such as pipelines and transmission lines that will interconnect these resources. The transition to decarbonization shows how stranded cost issues are not unique to old resources, but will be increasingly important for new investments. We highlight here the stranded investment issues decarbonization presents for some of these resources, which are already giving rise to new pleas for stranded cost compensation by incumbent firms in the industry. We focus on fossil fuel power plants, nuclear power plants, and energy transportation infrastructure.

A. Fossil Fuel Power Plants

Coal and natural gas power plants account for more than 60% of the grid's energy supply portfolio.[83] Many of these plants have already been in operation for decades. Given the high fixed costs that have been paid to build and keep these plants in operation, firms face strong incentives to keep them in operation as long as they produce positive revenue streams from energy sales. The marginal costs to the firm of using these plants to produce energy can be very low, depending on the price of the fuel they use to produce the next unit of energy.[84] The impact of the carbon transition on these "legacy" fossil fuel plants presents one of the most significant stranded cost barriers to the decarbonization transition.

Coal-fired power is the obvious loser in the transition to a low-carbon future.[85] The Clean Power Plan (CPP) expressly contemplates a phase-out of existing coal—to be replaced in the short term by increased utilization of natural gas combined cycle (NGCC),

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82 *See Coal is Going, Going, Gone?*, UTILITY DIVE BLOG, April 24, 2014, at http://www.utilitydive.com/news/coal-is-going-going-gone/253641/ (discussing EIA's predictions of the retirement of a significant number of coal-based power plants, along with a growth in natural gas power generation); Hammond & Spence, *supra* note >> (discussing challenges for nuclear power plants).

83 *See What is U.S. Electricity Generation by Source*, at https://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3.

84 For an overview, see Hammond & Spence, *supra* note >>, at 156-63 (providing comparative cost profiles of various electricity fuels).

85 Hammond & Pierce, *supra* note >>, at 2. Of course, if carbon capture and sequestration (CCS) becomes a viable technology, there may yet be a role for coal. EPA's carbon emission rule for new power plants requires at least some use of this technology. Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,509, 64,512-13 (Oct. 23, 2015) [hereinafter, "GHG New Source Standards"]..

and ultimately by increased new renewables penetration.[86] Moreover, other Clean Air Act (CAA) mandates—including the Cross-State Air Pollution Rule[87] and the Utility MACT Rule[88]—have put pressure on coal-fired power in recent years, increasing both the capital and operating costs associated with such plants.[89] These are regulatory changes, but they should not be a surprise. The 1990 Clean Air Act Amendments directed EPA to address both cross-state air quality issues for criteria pollutants and toxic emissions from the power sector.[90] And although greenhouse gas (GHG) regulation under the CAA may have come as a surprise to some,[91] the power sector's role in climate change has long been recognized.[92] At the very least, serious conversations about mitigation in the United States are nearing a decade old.

Market forces have also put pressure on coal. Natural gas has stepped in as a baseload competitor; its low prices have made it attractive to investors funding new power plants, and have also contributed to low short-run marginal costs, making it a hard competitor to beat on the competitive wholesale markets.[93] In fact, in its rule for new sources of carbon dioxide emissions in the electricity sector, EPA justified its strict approach for coal-fired power partly by explaining that very little new coal will be built anyway given these market forces.[94]

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[86] For an early look at the projected future electricity fuel mix under the CPP, see Energy Info. Admin., Annual Energy Outlook 2016, *Effects of the Clean Power Plan* (June 20, 2016), at https://www.eia.gov/forecasts/aeo/section_issues.cfm#cpp.

[87] Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed. Reg. 48,208 (Aug. 8, 2011); *see* EPA v. EME Homer Generation, Inc., 134 S. Ct. 1584 (2014) (upholding CSAPR).

[88] The MACT Rule was held unlawful in *Michigan v. EPA*, 135 S. Ct. 2699 (2015); however, the Rule remained in effect and EPA has now issued a supplemental finding meant to address the deficiencies. Supplemental Finding that It Is Appropriate and Necessary to Regulate Hazardous Air Pollutants From Coal- and Oil-Fired Electricity Generating Steam Units, 81 Fed. Reg. 24,420 (Apr. 25, 2016). Some coal companies actually argued against a stay because they had already convinced their state PUCs to permit them to recover the costs for new pollution control equipment.

[89] *See* EIA, AEO 2016, *supra* note >>, at 27 (attributing most coal retirements to these two rules); Neil Copeland & Debashis Bose, BLACK & VEATCH, *Impact of Coal Plant Retirements on the Capacity and Energy Market in PJM* 1 (2012) (describing 28 GW of coal-powered capacity slated to retire by 2020, partly due to CSAPR and MACT rules), at http://bv.com/docs/reports-studies/impact-of-coal-plant-requirements-on-the-capacity-energy-market-in-pjm.pdf.

[90] *See* Michigan v. EPA, 135 S. Ct. 2699, 2704-96 (2015) (describing 1990 amendments for hazardous air pollutants); *Clean Air Act Amendments of 1990 Summary*, available online at https://www.epa.gov/clean-air-act-overview/1990-clean-air-act-amendment-summary

[91] Massachusetts v. EPA, 549 U.S. 497 (2007).

[92] *See* Stephen Ferrey, *International Power on "Power*,*"* 45 ENVTL. L. 1063 (1063) (describing history of efforts to use renewable electricity rather than fossil-fueled electricity for climate change mitigation purposes).

[93] *See* Hammond & Spence, *supra* note [22], at 158-63 (describing comparative cost data and considerations for various electricity fuels); *see also* EIA, Electric Power Monthly, Tbl. 1.1, Net Generation By Energy Source: Total (All Sources), 2006-March 2016 (May 25, 2016) (presenting power generation figures showing increasing contributions of natural gas to power generation, culminating with its generating approximately the same amount of power as coal in 2015).

[94] GHG New Source Standards, *supra* note 85, at 64, 513-14.

The result is that coal-fired power plants are closing, coal companies are going bankrupt,[95] and coal's share of power generation is expected to decrease from well over half in the 1990s and early 2000s to about 18% by 2040.[96] Despite these negative results for coal companies and coal-industry workers, there are significant carbon and other air-quality benefits to be gained by weaning ourselves from coal.[97] But it is also true that there are social costs associated with closing these plants. In parts of the country where natural gas pipeline capacity is lacking—for example, the northeast during winter's high demand—coal provides the security of reliability because the fuel itself is easily stored.[98] Furthermore, the economies of coal-producing states like West Virginia are heavily dependent on the resource. As just one metric, tens of thousands of jobs have been lost in the the coal industry in recent years..[99]

As coal's share of the electricity supply wanes, natural gas's share is growing. In many states today, almost all of the new power plant capacity coming online is natural gas. The use of natural gas to produce electricity is expected to continue to increase in the near future, given its abundant supply, low costs relative to other fuel sources, and lower carbon impacts compared to other fossil fuels.[100] In contrast to older baseload coal plants, natural gas plants are usually built as peaking resources (i.e., those that are primarily deployed to meet peak customer loads) and offer many efficiencies as load following resources that can complement the integration of variable resources such as wind and solar into the grid.[101]

Yet one lurking concern is overinvestment in natural gas power plants for purposes of power supply, which could readily lead to overreliance on the fuel as a generation resource. For example, the Union of Concerned Scientists has warned that many states' heavy short-term reliance on natural gas plants presents a long-term risk of locking in investments in power plants that could peak in use by 2030, potentially creating massive new excess capacity problems.[102] Concerns with the grid's future overreliance on natural gas are heightened by the need for increased decarbonization over the coming decades, as natural gas is not carbon-free; as some scholars have argued, meeting our climate policy goals will require "eliminating virtually all" of our natural gas

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[95] Charles Riley & Chris Isidore, *The largest U.S. coal company just filed for bankruptcy*, CNN MONEY (Apr. 13, 2016) (describing bankruptcy filings of Peabody Energy and Arch Coal).
[96] EIA, ANNUAL ENERGY OUTLOOK 2016 EARLY RELEASE: ANNOTATED SUMMARY OF TWO CASES 22 (May 17, 2016).
[97] *See* Hammond & Spence, *supra* note [22], at 172-73 (describing these issues and collecting sources).
[98] *Id*. at 165.
[99] Drew Haerer & Lincoln Pratson, *Employment trends in the U.S. electricity sector, 2008-2012*, 82 ENERGY POL'Y 85 (2015) (estimating loss of over 49,000 coal jobs during study period); Kris Maher & Dan Frosch, *Coal Downturn Hammers Budgets in West Virginia and Wyoming*, WALL ST. J. (Dec. 22, 2015), at http://www.wsj.com/articles/coal-downturn-hammers-budgets-in-west-virginia-and-wyoming-1450822015.
[100] EIA projects significant additions of natural gas capacity, whether or not the CPP remains in place. EIA, Annual Energy Outlook 2016, Early Release: Annotated Summary of Two Cases 22 (May 17, 2016).
[101] *See Natural Gas Fired Combustion Turbines Are Generally Use to Meet Peak Electricity Load*, available online at http://www.eia.gov/todayinenergy/detail.cfm?id=13191.
[102] *See* UNION OF CONCERNED SCIENTISTS, RATING THE STATES ON THEIR RISK OF NATURAL GAS OVERRELIANCE (October 2015), online at http://www.ucsusa.org/sites/default/files/attach/2015/12/natural-gas-overreliance-analysis-document.pdf.

use by 2050.[103] The prospect of future stranded costs for natural gas, akin to what is currently being claimed in the coal industry, seems highly likely a decade or two into the decarbonization transition.[104]

B. Nuclear Power Plants

Nuclear power represents approximately 20% of the nation's power supply portfolio.[105] However, many existing plants are facing early retirement, largely as a result of the competitive electricity markets' failure to value carbon.[106] But decarbonization scenarios anticipate that nuclear power, which has no carbon emissions, will need to increase and new plants will need to be built.[107] This makes nuclear plants a significant potential stranded cost issue for the decarbonization transition as well.

Like coal, nuclear power provides steady, reliable baseload electricity with a fueling schedule that insulates it from the pipeline capacity issues that can plague natural gas.[108] Unlike coal and natural gas, nuclear power does not emit criteria pollutants, toxics, or greenhouse gases.[109] Thus, it has not been subject to the same CAA regulatory pressures as coal in recent years—though it has always been a highly regulated industry.[110] Nevertheless, nuclear power is struggling on the competitive wholesale markets; several plants have begun the decommissioning process, and others are currently listed as marginal.[111] The reasons relate to the dynamics of imperfect competitive markets. Because nuclear power must always run, it is a price-taker, meaning it will take whatever clearing price the wholesale markets provide regardless of its actual short-run marginal or long-run average costs.[112] Low natural gas prices and increasing renewables penetration have contributed to lower market clearing prices.[113] And without a price on carbon, the market is imperfect, making it harder for nuclear power to compete given its significant continued operational and safety costs.[114]

Nuclear power plants operating outside of the competitive wholesale markets have not encountered these challenges. In fact, the most prominent new reactors under

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[103] Weissman, *supra* note [3], at 8.
[104] *See also* Hammond & Pierce, *supra* note >>, at 14-15 (describing features of the CPP that may make natural gas plants an increasingly high-risk investment).
[105] *See* EIA, *supra* note >>.
[106] *See generally* Hammond & Spence, *supra* note [22] (providing detailed diagnosis).
[107] *See, e.g.*, PATHWAYS TO DEEP DECARBONIZATION, *supra* note [1].
[108] Hammond & Spence, *supra* note [22], at 165.
[109] Natural gas emits fewer of these pollutants than coal. *Id.* at 167. For a full discussion of the comparative environmental externalities of the various electricity fuel sources, see *id.* at 166-68.
[110] *See* Hammond & Spence, *supra* note [22], at 173-90 (arguing this level of regulation has caused nuclear power to internalize costs that are externalities for competitor fuel sources, putting it at a comparative economic disadvantage).
[111] *See generally id.*
[112] *Id.* at 189-90.
[113] *Id.*
[114] *See, e.g.*, MASS. INST. TECH., THE FUTURE OF NUCLEAR POWER (2003 & 2009 update), http://web.mit.edu/nuclearpower/ (illustrating cost competitiveness of nuclear power were carbon fully valued).

construction are in Georgia and South Carolina,[115] where the regulatory contract continues to provide cost recovery through ratemaking and can further be used to hedge future uncertainties.[116] Thus, whether a nuclear reactor is at risk of becoming a stranded asset may well depend on the restructuring status of its jurisdiction.[117]

From the perspective of a post-carbon grid, the position of nuclear reactors raises important stranded-cost issues—albeit issues that present different stakes than existing coal plants. Consider that existing reactors contribute over 60% of the nation's carbon-free electricity,[118] and when reactors are shut down, carbon emissions increase.[119] Achieving carbon emission reduction goals will require continued reliance on existing nuclear plants, as well as substantial new investment in nuclear plants.[120] The Clean Power Plan (CPP)[121] does not afford credit to states that retain existing nuclear power, but it does give credit for plant uprates and new reactors.[122] Further, the CPP contemplates that credit trading may be the easiest path to compliance.[123] Marginal plants thus face a temporal gap: at the moment—before the CPP has taken effect and while there is no real price on carbon—these plants could be considered stranded assets. But in the next decade, it is likely that their value from a carbon perspective will increase—whether from the CPP or some other climate change mitigation policy. New York, for example, has taken the policy view that nuclear power should help bridge today's carbon-heavy electric sector to the low-carbon grid of the future.[124] The stranded cost question is whether—and if so, how—to support these plants while we await regulatory and market dynamics that value their carbon contribution.

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[115] *See id.* at 188 (describing regulatory circumstances leading to new construction). As of this writing, the Tennessee Valley Authority (TVA) was conducting power ascension testing on the new Watts Bar Unit 2 reactor, which was licensed under an older procedural framework but was only recently completed. It is expected to begin commercial operation in summer 2016. *See* TVA, *Power Ascension Testing*, at https://www.tva.gov/Newsroom/Watts-Bar-2-Project (last visited June 8, 2016) (providing updates).

[116] *See infra* Part II >> (discussing these states' approaches to cost recovery for the carrying costs of construction).

[117] As is described *infra* Part III., the jurisdiction's restructuring status may also bear on states' options for addressing stranded cost issues.

[118] ENERGY INFO. ADMIN., STATE HISTORICAL TABLES FOR 2014 (rev. Nov. 2015).

[119] For sources regarding the closure of the Vermont Yankee power plant in Vermont, see Patricio Silva, ISO NEW ENGLAND, Environmental Update, Planning Advisory Committee, at 17 (Feb. 17, 2016); William Opalka, *CO_2 Emissions Increase in ISO-NE; Loss of Nuclear Plant Reverses Trend*, RTO INSIDER (Feb. 22, 2016). For sources regarding the closure of the San Onofre power plant in California, see Cal. Air Resources Bd., *2014 Edition: California GHG Emission Inventory* 4 (May 13, 2014). For experience in Japan following the moratorium on nuclear power following Fukushima, see Ministry of Economy, Trade and Industry, Gov't of Japan, *Long-Term Energy Supply and Demand Outlook* 4 (July 15, 2015).

[120] *See* PATHWAYS TO DEEP DECARBONIZATION, *supra* note [1].

[121] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,661 (Oct. 23, 2015) [hereinafter CCP] (to be codified at 40 C.F.R. pt. 60). The Supreme Court stayed the CPP during the pendency of litigation, which as of this writing is scheduled for oral argument before the D.C. Circuit Court of Appeals. North Dakota v. EPA, No. 15A793 (U.S. Feb. 9, 2016).

[122] CPP, 80 Fed. Reg. at 64,823.

[123] *See id.* at 64,823; Proposed Rule, Federal Plan Requirements for Greenhouse Gas Emissions From Electric Utility Generation Units Constructed On or Before January 8, 2014, 80 Fed. Reg. 64,966, 64,968 (Oct. 23, 2015).

[124] See sources collected *supra* note 16.

C. Energy Transportation

Energy transportation is also not exempt from stranded-cost issues with impending decarbonization. As noted above, construction of natural gas-fired power plants is projected to increase over the next decade or so. Yet natural gas-fired electricity requires not just power plants, but a transportation infrastructure. This necessity presents even trickier future excess capacity problems that relate to gas production as well as power plants.

Currently, there are a number of mismatches between the electricity and natural gas markets. Among the issues is pipeline capacity: natural gas is sold on spot markets, and the prices in recent times are significantly below their historically averages[125] Electric power suppliers buy natural gas on those spot markets, obtaining even lower prices by taking interruptible service.[126] Without long-term contracts, investors are reluctant to take on the significant financial commitment needed to construct new natural gas pipelines.[127] Paradoxically, natural gas is flared in some regions due to lack of pipeline infrastructure[128] even while there are shortages in other regions in the winter months when natural gas is in demand for both heating and electricity generation.[129] This lack of pipeline infrastructure has already created some stranded costs. In some areas of the country, for example, natural gas wells have been drilled but not completed due to the lack of transportation to get natural gas to market.[130]

The CPP's goals for carbon emission reduction contemplate that NGCC utilization in the nation's power supply portfolio—currently somewhere around 40%—could increase to as high as 75% to replace coal-fired generation.[131] Regional transmission organization such as PJM and MISO both contemplate that achieving this increased utilization would require major new pipeline infrastructure,[132] and the North American Electric Reliability Corporation (NERC) has warned that significant pipeline investment is needed to avoid reliability issues.[133] This presents another stranded-cost issue: will investors want to build this new infrastructure, knowing that the ultimate goal

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[125] *See Taking a Look at Historical Natural Gas Prices* (Jan. 25, 2015), available online at http://seekingalpha.com/article/2830226-taking-a-look-at-historical-natural-gas-prices

[126] *See* Hammond & Spence, *supra* note [22], at 165 & n.115 (collecting sources).

[127] For a full exploration of the contributing factors to a lack of pipeline capacity, see generally Alexandra B. Klass & Danielle Meinhardt, *Transporting Oil and Gas: U.S. Infrastructure Challenges*, 100 IOWA L REV. 947 (2015).

[128] The most notorious example involves flaring in North Dakota's Bakken field. *Id*. at 1009-15.

[129] FERC, WINTER 2013-2014 OPERATIONS AND MARKET PERFORMANCE IN RTOS AND ISOS 8 (Apr. 1, 2014), http://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf (describing significant electricity generation outages during polar vortex due to gas curtailment, lack of fuel diversity, and frozen coal).

[130] Klass & Meinhardt, *supra* note >>, at 1005.

[131] CPP, at 80 Fed. Reg. at 64,802-03.

[132] To nudge investors toward firm natural gas contracts, PJM has adopted new capacity market rules with significant penalties for generators that cannot dispatch when called. *See* Order Denying Request for Clarification, Granting in Part Request for Rehearing, 152 FERC P 61,064 (July 22, 2015); Order on Proposed Tariff Revisions, 151 FERC P 61,208 (June 9, 2015).

[133] NERC, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan* 24-25 (Nov. 2014).

of the electricity sector is to wean ourselves from natural gas as well as coal? Keep in mind as well that once that infrastructure is in place, there will be a new path dependency: stranded-cost concerns could mean reliance on natural-gas fired power longer than would be optimal from a climate change mitigation perspective.[134] New electricity transmission infrastructure presents similar stranded cost challenges: On one hand, regulatory certainty is necessary to attract capital investments to build transmission lines in new locations for the decarbonized grid. On the other hand, it is important that new transmission lines do not help to prolong the asset life of older fossil fuel generation power plants that would otherwise be retired – thus exasperating the carbon legacy plant problem highlighted above.[135]

III. Stranded Cost Compensation for Grid Decarbonization

These examples point to the almost intractable problem presented by irreversible energy infrastructure investment decisions and the path dependencies they create—an especially salient challenge given the transition to a significantly debarbonized energy grid. History shows how energy law is consistently inept at retiring energy infrastructure with any remaining life, though there are occasional counter-examples related to the decommissioning of specific hydroelectric and nuclear facilities.[136] With new stranded cost issues already occurring or predictable in the near future, we turn now to how such costs might best be handled as we transition to a decarbonized energy grid.

This Part first discusses whether, given structural changes the energy industry has undergone in recent decades, regulators today might be more justified than ever in ignoring stranded cost issues, including those associated with decarbonization's transition. But although these structural changes provide great promise for future private management of many investor risks, stranded cost compensation during the transition to deep carbonization may yet prove necessary. Still, regulators should not follow the model of past stranded cost experiments. Instead, in making decisions today about our future energy infrastructure, regulators have an opportunity to write a new stranded cost chapter for energy law, one that both facilitates the transition to decarbonization while providing a better balance between certainty and flexibility than in the past. Front-end stranded cost recovery for incremental energy infrastructure investment decisions can attract new capital for decarbonization by reducing uncertainty, while also ensuring that values associated with energy reliability and carbon impacts are not left stranded during the impending transition. In order to avoid distorting returns on investment to favor carbon lock-in, regulators must address stranded costs associated with existing energy

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[134] Of course, some argue that this is already true. This Article focuses on use of natural gas as a bridge fuel for electric power generation, as contemplated by the CPP. *See* Hammond & Pierce, *supra* note [22], at 14-15 (hypothesizing that expected future shifts away from natural gas may drive up prices in the near-term because of investor reluctance).

[135] *See, e.g.,* Jim Rossi, *The Trojan Horse of Transmission Line Siting Authority*, 39 ENVTL. L. 1015 (2009).

[136] With both of these examples, federal regulators played a significant regulatory role in decommissioning—a role that is not available for existing fossil fuel generation plants. *See, e.g.*, 10 C.F.R. Pt. 20 Subpart E (NRC regulations governing nuclear power plant decommissioning); FPL Energy Maine Hydro, LLC, 107 FERC P 61,120 (May 6, 2004) (ordering surrender of hydro license and partial dam removal, with licensee's agreement).

infrastructure under the same principles that they apply to incentives designed to reduce uncertainty in the investment in new resources.

A. The Promise of Private Management of Stranded Costs

William Baumol and J. Greogory Sidak once predicted that the "new mode of mixed competition and regulation" is one "in which no such problem [of stranded costs] need arise again."[137] Compared to fifty years ago, private investors today are much better equipped to address the risks of many energy transitions. The regulatory contract that once described the industry can no longer be understood as a deal between a few firms and the state.[138] Shifts towards competitive energy markets have created a regulatory environment that is much more multi-faceted in nature, with a range of firms, interest groups, and stakeholders now serving as the main participants in any regulatory bargain.[139] Energy regulation today is not understood as a binding bilateral deal subject to renegotiation each time a major new infrastructure decision is made, but is much more fluid and ongoing in nature.[140]

If FERC's competitive restructuring of wholesale gas and electric power markets had been effective in making the energy sector perfectly competitive, then no firm or investor in the energy industry today would face fundamentally different risks than any other business. Order 888 made clear FERC's preference for a market competition policy based on open access, but we should be careful not to overstate either the scope or success of competitive energy markets.[141] FERC's competitive restructuring efforts addressed only the wholesale side of domestic energy markets, and even today, that restructuring process is incomplete.[142] State regulators retain significant control over infrastructure related to retail gas and electric power sales, with most states continuing to apply traditional cost-based regulation to infrastructure decisions regarding these transactions.[143]

Even though the rules of the game for energy markets continue to evolve, it is undeniable that some structural changes have created the potential for better private management of business risks by firms and their investors. Under the traditional regulatory contract, firms and their investors were much more homogenous, with most regulation aimed at the traditional, vertically integrated utility. Today, the energy industry is comprised of a much more diverse range of investors operating outside of regulatory compact.[144] Most new power generation today, for example, is non-utility

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[137] Baumol & Sidak, *Stranded Costs*, *supra* note [14], at 839.
[138] Hammond & Spence, *supra* note [22], at 192.
[139] *Id*. at 192-93.
[140] *See* JIM ROSSI, REGULATORY BARGAINING AND PUBLIC LAW (2005).
[141] *See* Richard J. Pierce, Jr., *Completing the Process of Restructuring the Electricity Market*, 490 WAKE FOREST L. REV. 451 (2005) (contrasting promise and realities of restructuring the electricity markets).
[142] *Id*. at 460-61.
[143] *Id.*
[144] *Cf*. Richard F. Hirsch & Benjamin K. Sovacool, *Technological Systems and Momentum Changes: American Electric Utilities, Restructuring and Distributed Generations Technologies*, 36 J. TECHNOLOGY

generation—plants built by firms with whom no traditional regulatory compact can be said to exist.[145]

In addition, with a greater range of firms operating in the industry, private investors are better equipped to diversify risks themselves. For example, with the decline of the traditional utility's dominance in the electric power industry, today firms operating in national markets are better equipped to diversify their investments across jurisdictions and regions of the country.[146] Also, in part due to technological innovations, the scale of new energy supply investments is far smaller than the kinds of large-scale base load plants that were characteristic of new investments in the 1960s and 1970s.[147] This has allowed for multiple, smaller-scale investments by larger firms that are better able to diversify the assets on their balance sheets than utilities in the past.[148] For example, many firms with power plants that they consider to be uneconomic seek to securitize or sell these assets by selling them (or spinning them off),[149] instead of asking regulators for stranded cost recovery.

In addition, in recent decades financial regulation has improved the quality of information about investments that is available to investors in energy firms. Corporate disclosure expectations today are much more cognizant of potential changes in business and technological conditions as well as regulatory regimes.[150] One example is the historical popularity of many utility stocks as low-risk investment vehicles in worker pensions. Historically, pension managers may not have been required to disclose the full risks of these investments, but institutional disclosure requirements for investment managers have changed significantly.[151] Historical utility accounting practices, which were premised on rate recovery of asset costs, may have understated risks associated with long-term capital investments against the backdrop of changing conditions—a risk that firms today must disclose. Increasingly too, regulators are moving towards the disclosure of future risks associated with climate change, and this should better enable investors to price these risks in making future investment decisions.[152] There is some evidence to

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STUD. 72, 78 (2006) (describing a new diversity of stakeholders negotiating towards a new electric power industry consensus).

[145] *See* EIA, Electric Power Monthly (showing planned near-term capacity additions) (May 2016).

[146] For terrific general overviews of these structural changes, see STEVE ISSER , ELECTRICITY RESTRUCTURING IN THE UNITED STATES: MARKETS AND POLICY FROM THE 1978 ENERGY ACT TO THE PRESENT (2015); RICHARD F. HIRSCH, POWER LOFSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM (1999).

[147] Remarks of Jeff Riles, Jr., Director, Regulatory Affairs, Enel Green Power North America, Inc, at GW Law J.B. & Maurice C. Shapiro Environmental Law Symposium, Mar. 11, 2016 (notes on file with authors).

[148] *See* INTERNATIONAL ENERGY AGENCY, POWER GENERATION INVESTMENT IN ELECTRICITY MARKETS 14 (2003), at https://www.hks.harvard.edu/hepg/Papers/Fraser.gen.invest.elec.mkts.1203.pdf.

[149] These were commonly used strategies for addressing the stranded costs associated with electric power industry restructuring. *See* ISSER, *supra* note >>, at 200-03.

[150] *See, e.g.,* David Ruder et al., *The Securities and Exchange Commission's Pre- and Post-Enron Response to Corporate Financial Fraud: An Analysis and Evaluation*, 80 NOTRE DAME L. REV. 1103 (2005).

[151] *Id.*

[152] *See* Rick E. Hanson, *Climate Change Disclosure by SEC Registrants: Revisiting the SEC's 2010 Interpretive Release*, 6 BROOK. J. CORP. FIN. & COM. L. 487 (2012) (discussing SEC rules requiring

suggest that disclosure may encourage firms to do little more than reassure investors,[153] but at the very minimum investors today in the energy sectors are better informed about risks than investors half a century ago.

These changes in the nature of regulation, industry structure, and risk disclosure may not make concerns about transition costs irrelevant. But we would expect private investors to be much better equipped to deal with transitions, especially where they involve business assumptions or technology decisions over which investors are able to assume risks themselves, or over which the firm has some degree of control. After all, the history of energy regulation shows that transition is the only certainty, so we should not allow new investors to claim surprise for the kinds of business risks that they can control.[154]

Consider again the fuel costs that drove the stranded cost problem with pipelines' take-or-pay contracts. Today, a pipeline operating on a national scale would be well positioned to address the risks of changes on its own, and to hedge its take-or-pay contracts with other instruments. Such developments point to modern investors being much better equipped than in the past to address the stranded cost problem in making their own risk decisions, particularly to the extent that stranded costs issues reflect nothing more than ordinary business risks. Of course, we can still expect that the sheer size of many energy infrastructure investments—along with their long-lived asset life—will produce more significant transition cost problems down the road than are faced by most sectors of the economy, but that should not deter regulators from encouraging private investors to act on their own to price the risks of changes at the front end, where they can do so.

B. Complementary Stranded Cost Recovery Mechanisms

Given the many private mechanisms for managing the risk of stranded costs, one might argue that regulatory approaches for stranded cost recovery going forward are either unnecessary or poor public policy because they create disincentives to address the issue in the marketplace. No doubt, the regulatory process can do a better job of encouraging investors to price risks themselves, especially the business risks of future economic or technology changes. Encouraging investors to price these kinds of risks at the time they make a decision to invest in assets could help to shift such risk to investors, allowing regulators to focus on pricing those risks and transition costs over which they have a comparative advantage, namely, the residual risk of unexpected regulatory change or other values that are not represented in the competitive market.

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disclosure of climate change risks); *see also* Sey-Hyo Lee & Maruskha Bland, *Carbon Transparency*, FORTNIGHTLY, May 1, 2008, at 16

[153] *See, e.g.,* James Coleman, *How Cheap is Corporate Talk? Comparing Companies' Comments on Regulations With Their Securities Disclosures*, 40 HARV. ENVTL. L. REV. 47 (2016) (describing how oil companies told federal regulators that a renewable fuel standard would harm them financially while simultaneously telling investors that they are well positioned to comply with any new requirements).

[154] *See, e.g.*, Charles River Bridge, discussed *supra* at Part I.A.

The regulatory bargain in energy markets remains much more of a moving target than in most other sectors of the economy. Existing energy infrastructure may be more capital-intensive and long-lived than the assets in other sectors of the economy, but even in other sectors it is recognized how important it is for regulators to be attentive to the transition costs associated with regulatory change.[155] Changes in the energy industry in recent decades thus do not render stranded costs concerns irrelevant, but provide energy regulators an opportunity to give stranded cost recovery a new focus, better aligning investor signals with core public values. We believe that stranded cost compensation with the decarbonization transition presents some unique opportunities for regulatory reform that can avoid stranded cost myopia, especially to the extent that prices and investment signals in competitive energy markets fail to value reliability and environmental attributes of energy resources.

To begin, consider the massive levels of infrastructure investment that will be required to meet the goals of decarbonization. Keeping warming under 2 degrees Celsius is estimated to require hundreds of billions of dollars of new capital investment over the coming decades.[156] Presumably, many of these new energy infrastructure investments will be pursued because of their carbon emissions advantage over existing energy supply resources. Unless the carbon attributes of energy supply are somehow priced in all market decisions concerning these resources, however, the returns that firms offer to investors may be too low to attract new investments, leading to underinvestment in new resources and overdependence on old ones. In addition, uncertainties and high costs surrounding new resources such as next-generation nuclear plants, offshore wind, and electric power transmission have frightened investors from sinking capital into such projects. To make new technological investments attractive, and to achieve the right balance of energy resources for decarbonization, the returns offered to investors must provide some premium for uncertainty while also pricing the carbon attributes and other values that are important to the energy system. As is discussed above, traditional stranded cost compensation gave little or no discussion to these forms of stranded benefits in the calculated of stranded costs. Regulators paying attention to stranded costs recovery as a mechanism for reducing uncertainty and addressing these values ex ante – i.e., before each energy resource investment decision is made – may better facilitate a transition to decarbonization that is attentive to the balance of resources in the energy system as a whole. By avoiding wasteful ex post lobbying to address stranded costs decades from now, it also could help to reduce the overall cost of capital for a decarbonized energy system.

But approaching stranded costs only as a way of incentivizing investors to steer capital to new decarbonized energy resources could also also be counterproductive. The

[155] *See* Richard L. Revesz & Allison L. Westfahl Kong, *Regulatory Change & Optimal Transition Relief*, 105 NW. U. L. REV. 1582 (2011) (discussing transition problems with grandfathering pollution from old power plants). *See also* Louis Kaplow, *An Economic Analysis of Legal Transitions*, 99 HARV. L. REV. 509 (1986); Steven Shavell, *On Optimal Legal Change, Past Behavior, and Grandfathering*, 37 J. LEGAL STUD. 37 (2008).
[156] *See* PATHWAYS TO DEEP CARBONIZATION, supra note >>, at 47 (noting the need for an increase in new investments in the range of $15-70 billion annually between today and 2050).

transition to decarbonization is plagued by an old resource problem too, which if left unaddressed can readily reinforce carbon lock-in.[157] It is thus imperative to recognize the challenge of addressing both new and old capital investment with the transition to decarbonized energy infrastructrure. Subjecting old energy infrastructure to a different stranded cost recovery than the principles used to incentivize investments in new infrastructure risks distorting investor returns to favor carbon-lock by delaying new investments.

With respect to existing investments, such as those discussed in Part II, stranded cost recovery will remain important to ensuring that the transition to decarbonization occurs in a timely manner, and is not delayed further by path dependency. While we are not proposing a bailout of all existing assets, a failure to address stranded costs concerning decarbonization of existing energy supply resources risks the possibility that some transitions may never occur. Past experience has shown that some stranded cost recovery might be a worthwhile price to pay for industry cooperation or even stakeholder buy-in in the midst of a transition.[158] Equally important in addressing stranded costs for existing resources, however, regulators must be attentive to some important issues that they have ignored in the past, or they will fail to address the social costs of transitions. Specifically, as with new energy infrastructure, the transition issues presented by existing resources underscores the importance of recognizing attributes of different energy resources that competitive energy markets today do not value in their pricing mechanisms in calculating stranded costs.

Before we proceed, we emphasize that our argument is pragmatic: we are not contending that any one kind of stranded cost recovery is the most economically efficient regulatory approach,[159] or that it is required as a matter of contract or the Constitution.[160] Instead, the regulatory approach we propose can provide forms of stranded cost recovery that are politically expedient, reasonably justifiable, and useful for easing the transition to a clean energy future.

1. Temporal Approaches and Considerations

As our historical examples show, energy law has traditionally dealt with stranded costs for investors and firms once they arise, often long after initial private investment decisions are made. This ex post form of stranded cost recovery contributes to some

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[157] Unruh, *supra* note >>.

[158] *See, e.g.*, Jim Rossi, *Can the FERC Overcome Special Interest Politics?*, 133 No 19 PUB. UTIL. FORT. 31, 33 (1995) (describing FERC's carrot/stick approach to minimizing special interest resistance to electricity restructuring); *see also* Richard J. Pierce, *The Evolution of Natural Gas Regulatory Policy*, 10 SUM. NATURAL RESOURCES & ENV'T 53, 83 (1995) (describing how transition from regulatory contract to regulated market creates stranded costs, incentivizing industry to stall).

[159] The focus of this Article is on whether and how stranded cost recovery should be allowed by regulators, and what core values it should reflect. It does not address the actual financial calculation of stranded costs. For discussion of various methods of calculating actually stranded costs, see CBO REPORT ON DEREGULATION AND STRANDED COSTS, supra note [62]; SIDAK & SPULBER, *supra* note [59], at 394-96; Ajay Gupa, *Tracking Stranded Costs*, 21 ENERGY L.J. 113 (2000).

[160] *Cf.* Rossi, *The Irony of Deregulatory Takings*, *supra* note [61].

problematic behaviors in the regulatory process, by encouraging firms and their investors to lobby against change, as well as discouraging firms and regulators from being attentive to stranded benefits and to the public values that need to be protected in transitioning to a new normal.[161] It should not come as a surprise that the past forms of stranded cost compensation produced by this kind of regulatory process have appeared to be little more than a bribe to buy industry acquiescence in energy sector changes or, worse yet, a bailout that comes at the cost of consumers. If the history of energy law teaches anything, however, it is that transitions and change ought to be expected in the energy sector. It follows that regulatory approaches that force both regulators and investors to consider stranded cost issues in making current investment decisions, rather than only leaving them for the future, are worth consideration. Here we canvass just a few examples to show that energy regulators are already considering this as a way of encouraging new investments associated with grid decarbonization

One way to encourage such investments to build expensive new infrastructure projects, especially where there is uncertainty about the future, is to accelerate recovery for construction costs to the front end, when construction is actually occurring—rather than requiring infrastructure to be actually built and operating before recovery is permitted.[162] Several jurisdictions permit this approach, which is being used most notably for the only new nuclear reactors under construction.[163] This approach incentivizes investors to move forward with significant capital undertakings even against the backdrop of uncertainty by lessening any concern that if regulatory treatment of a project changes mid-construction, they will not have to repeat history's nuclear cancelation episode. On the other hand, this approach shifts some of the burden of this uncertainty to

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[161] *See supra* Part I.B.2.

[162] This is typically referred to as the "used and useful" requirement, and is found in a number of jurisdictions' statutes. For example, Pennsylvania law required that rates for electricity be fixed without consideration of a utility's expenditures for nuclear power generation plants that were planned but never built because they were not "used and useful in service to the public." 66 Pa. Stat. §1315 (Supp. 1988). Utilities incurring millions of dollars in preliminary construction expenses to recover these costs from customers sued Pennsylvania regulators, alleging that this was an unconstitutional taking of their property without just compensation in violation of the Fifth Amendment of the U.S. Constitution. Ultimately, the U.S. Supreme Court upheld the Pennsylvania law, reasoning that the "end result" was just and reasonable and the Takings Clause does not dictate a specific method for cost recovery. Duquesne Light Co. v. Barasch, 488 U.S. 299, 314 (1989) ("The economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result. The Constitution is not designed to arbitrate these economic niceties.").

[163] *See* Mid-Tex Elec. Coop., Inc. v. FERC, 773 F.2d 327, 330-36 (D.C. Cir. 1985) (discussing FERC's methods of cost recovery during construction, includigng allowance for funds used during construction (AFUDC) and construction work in progress (CWIP)); Georgia Nuclear Financing Act, O.C.G.A. § 46-2-25(c)(3) (2009) (note that Georgia's statute applies only to nuclear reactors approved within a limited time window, making Southern Company the only eligible company); Georgia Power's Application for the Certification of Units 3 and 4 at Plant Vogtle and Updated Integrated Resource Plan, No. 27,800, 2010 WL 2647607 (Ga. Pub. Serv. Comm'n June 17, 2010) [hereinafter *Georgia Power's Application*] (finding Georgia Power's inclusion of CWIP in rate base would benefit ratepayers). *Compare* Base Load Review Act, S.C. CODE ANN. § 58-33-220(2) (2011) (extending CWIP recover to both nuclear and coal, provided that coal plants must comply with Best Available Control Technology for air emissions as defined by EPA); FLA. ADMIN CODE ANN. r. 25-6.0423(6) (2007) (permitting a utility to petition the Florida Public Service Commission to recover carrying costs).

customers. Their interests are protected only minimally: they have the predictability of CWIP being spread over a set time period, and (using Georgia as an example) they have at least some oversight through the regulatory process, which requires periodic reports by the utility.[164] But construction disputes, delays, and increased costs can remain an issue.[165]

Cost recovery can also be apportioned to in-service assets as they come online, enabling investors to earn a return even for projects that are not yet fully complete. For example, Mississippi Power's Kemper County Energy Facility is an integrated gasification combined cycle (IGCC) plant that will be accompanied by carbon capture technology.[166] It is designed to use lignite coal and will be the first plant to employ these technologies at this scale (its capacity is 582 MW). It is not yet fully online, but the state's PUC has approved cost recovery for the parts of the plant that are already in service and generating electricity. The Kemper facility has also been plagued by construction delays and increased costs,[167] but these have been allocated somewhat between investors and customers. There is a cap on the costs to customers associated with the power plant portion of the project,[168] but uncapped costs are those associated with the lignite mine, CO2 pipeline, and "improvements to design."[169] Mississippi Power's parent company reports it has taken a $2.5 billion write down.[170]

At the federal level, the Modified Accelerated Cost Recovery System (MACRS) permits certain renewable energy projects to recover their investments through depreciation deductions.[171] To qualify for the 50% first-year bonus depreciation, these projects must be in service by January 1, 2018.[172] Some states are also allowing for an excise tax on energy sales to finance a trust fund to jump start renewable investments[173] or have consider guaranteed cost recovery for renewable projects, to avoid the used and useful uncertainty that plagued nuclear plants.[174]

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[164] *See, e.g.*, O.C.G.A § 46-3A-7(b) (requiring monitoring reports); *Georgia Power's Application*, *supra* note >> (additionally requiring monthly status reports on CWIP).
[165] *E.g.*, Thomas Overton, *Even More Delays and Cost Overruns for Vogtle Expansion*, POWER (Feb. 2, 2015) (detailing new reports of cost overruns, delays, and construction litigation).
[166] *See* Mississippi Power, *Facts*, at http://www.mississippipower.com/about-energy/plants/kemper-county-energy-facility/facts.
[167] Indeed, the plant lost its tax credit because it opened too late.
[168] *See* Mississippi Power, *Kemper County energy facility*, at http://www.mississippipower.com/pdf/kemper/Kemper-Cost-Breakdown.pdf.
[169] *Id.*
[170] *Id.*
[171] Dep't of Energy, *Modified Accelerated Cost Recovery System (MACRS)*, at http://energy.gov/savings/modified-accelerated-cost-recovery-system-macrs (last visited June 7, 2016).
[172] *Id.*
[173] *See, e.g.,* RENEWABLE ENERGY RESULTS FOR MASSACHUSETTS: A REPORT ON THE RENEWABLE ENERGY TRUST FUND 1998-2008 (2008), online at http://masstech.org/sites/mtc/files/documents/2008%20Renewable%20Energy%20Trust%20Report_0.pdf.
[174] Section 366.92(4), of Florida Statutes, enacted in 2008, provides for full cost recovery by a public utility of all reasonable and prudent costs incurred for renewable energy projects that are zero greenhouse gas emitting at the point of generation, up to a total of 110 megawatts statewide. Florida has also considered allowing renewable projects should be allowed similar early cost recovery to that available for nuclear plants. However, so far these proposals have not been enacted into law.

These examples show just a few ways that regulators can address uncertainty by providing investors some compensation for risk early on—whether during construction or early in an asset's life—so that the project's full lifetime need not pass before investors fully receive compensation for the risks they take on in their investments. For those capital-intensive projects involving first-mover technologies, or projects facing high levels of uncertainty, such arrangements can help alleviate investor reluctance. They come at some cost initially, but by reducing investor uncertainty, they have promise of reducing the overall regulatory cost of capital for projects in comparison to only allowing for stranded cost recovery decades into the future. Either customers or taxpayers will bear these stranded costs, however, so it remains crucial for a regulatory process that carefully assesses the need for the project and the overall benefits and burdens to ensure that the investments are worthwhile. By placing all of these decisions at the front end of a regulatory examination of the value of energy infrastructure, such a temporal shift would better allow regulators to look at how the cost of capital for each energy resource fits into a more general assessment of the cost of capital for the firm and for the energy system more generally as we transition toward grid decarbonization.

One concern with these methods of temporal risk shifting is that, to the extent that they focus solely on the present value of the investor or firm's financial costs, they treat the non-investor attributes of all energy resources the same. For example, basing early stranded cost recovery purely on compensating market risk treats the environmental and reliability attributes of every energy resource equally, even if these are not valued by investors because of the lack of any current pricing mechanism that produces a revenue stream. As an illustration, new natural gas plants are often touted as providing a "bridge" to the low carbon energy system, while a new nuclear plant may provide a longer-term resource for decarbonization.[175] Even if the financial risks associated with each project were otherwise similar, providing similar risk compensation to incentivize investments in both resources would lead to overinvestment in gas plants and contribute to carbon lock-in by delaying their retirement in the future, when lower carbon alternatives can be deployed. In other words, unless other public values are considered in setting these incentives, early stranded cost compensation based entirely on reducing financial risks to investors could readily suffer from the same narrow-mindedness as past stranded cost compensation, effectively leaving stranded public values that are central to the transition to decarbonization.

Regulators in the past have failed to address stranded benefits and broader values beyond investor protection, in part because an ex post stranded cost compensation regulatory process rewards firms that ignore or withhold disclosing them. In the past, firms seeking ex post compensation did not have incentives to claim future benefits that

[175] One study, for example, see production of electricity from natural gas peaking in the year 2030, after which its deployment will begin to decline. *See* Nelson et al., supra note >>, at 25. On the stranded cost problem associated with natural gas infrastructure, see also Robert Walton, *Why Natural Gas Investments Could Spell Trouble for Electric Utilities*, UTILITY DIVE, Feb. 8, 2016, online at http://www.utilitydive.com/news/why-natural-gas-investments-could-spell-trouble-for-electric-utilities/413368/.

might offset these costs until the stranded cost compensation is resolved.[176] By contrast, addressing stranded costs at the front end would force all firms offering energy resources to be transparent about both the costs and benefits associated with those resources. To combat concerns about certain energy values or attributes not being priced in energy markets–for example, absent a carbon price, low-carbon energy resources may fail to attract investors in the first place--legislatures or regulators could address environmental attributes in approaching incentives designed to attract investors to new projects. Alternatively, regulators could condition early recovery and other approvals on sunset provisions.[177] For example, a legislature concerned about the need to ultimately shift away from natural gas might set schedules tapering the availability of cost recovery over time.[178] Plants' licenses could also include firm expiration dates, creating a presumption of closure rather than renewal.[179]

Shifting compensation for these kinds of risks to the front-end of an asset's may, of course, increase the firm's cost of capital for some new energy projects. Inevitably, this will come at some cost to consumers, but no one claims that the transition to decarbonization will be cheap. A higher return on investment will be essential to attracting new investors to low carbon infrastructure such as next-generation nuclear power plants, large-scale renewable plants, and expensive new transmission lines to facilitate broader regional deployment of renewable energy. In addition, although the cost of capital for some investments may go up when initial investments are being considered, it is not clear that the firm's overall cost of capital (or what is known as the regulatory cost of capital) will follow suit, as regulators decades into the future will not face the same pressures of wasteful lobbying by incumbent firms to provide for back end stranded cost recovery.[180] And even if the cost of capital for some firms were to increase, applying these kinds of principles to all investment compensation decisions would work to reduce the system-wide (trans-firm) cost of capital related to decarbonized energy infrastructure.

Equally important, providing incentives to attract investors to new decarbonized energy investments cannot, on its own, overcome lock-in where existing carbon-intensive energy resources remain in operation, facing lower marginal operational costs. Raising the return on investment to address uncertainty for new resources would attract new

[176] *See supra* note >> (citing accounting article on this disclosure problem with ex post stranded cost recovery).
[177] One recent article refers to these kinds of proactive limited approvals as "sunrise" provisions. *See* Chris Serkin & Michael Vandenbergh, forthcoming . . . . . . (arguing for a sort of sunset on the approval of new energy resources that have an adverse carbon-impact, based on a front incentive coupled with an enforceable promise not to lobby for keeping the resource in operation indefinitely) (on file with authors).
[178] *See also* Weissman, *supra* note [3], at 2 (proposing that legislatures set final dates after which no new NG plants will be approved).
[179] Of course, whether this would be a state or federal option would depend on the type of plant.
[180] To the extent there is full recovery in present value for the risks associated with stranded costs at the front end, an enforceable regulatory mechanism to "sunset" permits or plants could help limit investors for having a second-bite at apple and lobbying regulators for such recovery in the future. *See* Serkin & Vandenbergh, *supra* note [182]. Absent such a provision, any ex post assessment of stranded cost would need to be considered nothing more than a true-up to past compensation. We acknowledge of course, that wasteful lobbying for other reasons is a fact of our political society.

investment dollars, but this could backfire if, once new infrastructure goes online, the marginal costs of deploying low-carbon resources do not compare favorably to carbon-intensive resources built decades ago.[181]

To avoid carbon lock-in it is thus just as imperative for regulators to address stranded costs for existing energy resources, such as the examples involving older nuclear and coal plants that we have highlighted in Part II, in a similar manner. For example, regulators providing stranded cost compensation for existing resources should not only be attentive to protecting a firm's investors to ensure that financial risks are sufficiently compensated, but they must also be attentive to the reliability and environmental attributes of energy resources. This might, for example, lead regulators to approach stranded investments for some existing coal plants differently from some existing nuclear plants, or for treating existing gas pipelines differently across geographic areas, based on the need for capacity to support decarbonized energy infrastructure in different regions. If incentives for new energy resources compensate investors for risks in a manner that contemplates values such as reliability and environmental attributes, so too should compensation for risks associated with older resources. A failure to treat risk compensation for new and existing resources in a similar manner regarding these values in stranded cost compensation could distort the cost of capital to favor existing resources, resulting in the same kind of wasteful delay that characterized grandfathering of existing power plants under the Clean Air Act.[182]

2. *Reconciling (Some) Stranded Cost Recovery With Competitive Markets*

In most of the examples discussed above, cost recovery through ratemaking is the norm (as it remains in most states), and regulators can creatively permit investors to receive early compensation for risks to avoid future stranded cost issues. But, to raise an issue that has puzzled energy lawyers at least since FERC's Order 888, what regulatory approaches are available in competitive interstate energy markets? We believe that overcoming stranded cost myopia with the transition towards decarbonized energy infrastructure will require energy law to resolve some of these issues, and offer here a few thoughts on steps toward that goal.

Consider again the current issue of marginal merchant nuclear power plants, which are at risk of early closure notwithstanding their reliability and climate benefits. As suggested above, this particular stranded cost issue is driven by an imperfect market,[183] and there are good reasons to treat these resources differently than fossil-fueled plants because of their comparative reliability and environmental benefits. The question that remains, however, is whether regulators can endorse compensating investor risks for certain forms of power generation against the backdrop of competitive interstate energy

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[181] One of the authors has made this point, suggesting that once built, new transmission lines might be utilized to favor existing resources like coal plants with lower marginal costs. *See* Rossi, *Trojan Horse of Transmission Line Siting*, *supra* note [138] (making this point).
[182] *See, e..g.*, Revesz & Kong, *supra* note [160], at 1632.
[183] As is discussed in Hammond & Spence, *supra* note [22].

markets, or whether federal competition policy preempts regulators from taking such an approach.[184]

The Supreme Court's recent decision in *Hughes v. Talen Energy Marketing*[185] likely places some constraints on stranded cost recovery, at least for issues arising from flaws in the wholesale markets. In *Hughes*, the Court invalidated a Maryland scheme that provided incentives for constructing new natural gas plants.[186] Perceiving the wholesale capacity market to be insufficient to incentivize new construction within its borders, Maryland enacted a scheme whereby the power plant owners would be compensated with a fixed revenue stream for capacity that cleared the relevant market.[187] In other words, the compensation was designed to provide more revenue for the plants than what they would receive on the capacity market..[188] Maryland is one of thirteen states that have authorized their utilities to operate in PJM – a regional transmission organization that operates the largest organized wholesale power market in the United States. Under the Federal Power Act (FPA), FERC has "approved the PJM capacity auction as the sole rate setting mechanism for sale of capacity to PJM, and has deemed the clearing price per se just and reasonable."[189] Because Maryland's auction for new in-state generation interfered with FERC's exclusive jurisdiction over interstate wholesale sales of energy under the FPA, the Court upheld a lower court determination that the Maryland scheme is preempted under the Supremacy Clause of the U.S. Constitution.[190]

The Court left observors questioning how far beyond its facts *Hughes* might extend.[191] Although it expressly emphasized the narrowness of its holding,[192] the Court suggested that states may not tether revenues to wholesale market participation or condition payments on capacity clearing the relevant auction.[193] At the same time, the Court left open "the permissibility of various other measures States might employ to encourage development of new or clean generation, including tax incentives, land grants, direct subsidies, construction of state-owned generation facilities, or re-regulation of the

184 For arguments suggesting that states' policy options are constrained depending on their restructuring status, see Hammond & Spence, *supra* note >>, at 209; Hammond & Pierce, *supra* note >>, at 16-17.
185 Hughes v. Talen Energy Marketing LLC, 136 S. Ct. 1288 (2016).
186 New Jersey attempted a similar approach, which the Third Circuit invalidated in PPL Energyplus, LLC v. Solomon, 766 F.3d 241 (3d Cir. 2014).
187 136 S. Ct. at 1293.
188 *Id.* at 1293.
189 *Id.* at 1297..
190 *Id.* at 1299.
191 *E.g.* Emily Hammond, *Hughes v. Talen Energy Mktg, LLC: Energy Law's Jurisdictional Boundaries: Take Three*, GEO. WASH. L. REV. DOCKET (Oct. Term 2015), at http://www.gwlr.org/hughes-v-talen-energy-marketing-llc-energy-laws-jurisdictional-boundaries-take-three/.
192 *Id.* at 1299 ("Our holding is limited: we reject Maryland's program only because it disregards an interstate wholesale rate required by FERC.").
193 *Id.*

energy sector."[194] The concepts of "tethering," "conditioning," and "re-regulation" all suggest limits on the spectrum of state options in moving toward decarbonization, but the contours of those limits are unclear.

Hughes appears to constrain the ability of state regulators to adopt investment incentives to compensate investors for their risk (including stranded cost recovery) if these target federal wholesale power market prices. After all, these kinds of incentives or subsidies would seem to be fundamentally at odds with federal policies favoring competitive power markets, especially to the extent that they invite states to give incumbent firms favorable treatment over out-of-state sources of energy or otherwise distorting price signals in interstate markets. Indeed, FERC's initial response to the decision indicates some hostility towards stranded cost recovery for legacy coal or nuclear plants that are no longer competitive in regional wholesale power markets operating under similar rules as in Maryland.[195]

In traditionally regulated states like Georgia and South Carolina, however, forward-looking regulatory initiatives for new clean energy construction do not seem problematic. These states are not within competitive wholesale markets like PJM, nor have they restructured at the retail level.[196] Unlike Maryland, therefore, these states have retained their full authority to decide what values to compensate. Although wholesale costs must be carried forward into state ratemaking proceedings,[197] states retain authority to set the utility's return on investment. Moreover, the wholesale costs in these states are not derived from comptetitive auctions, but rather from bilateral contracts.[198] Providing compensation for the carrying costs of construction, therefore, do not "second-guess" or "disregard[] an interstate wholesale rate FERC has deemed just and reasonable…."[199] Thus, in contrast to the regional capacity market that FERC had approved for PJM, in many other parts of the country retail reliability (and the need for new power supply capacity) remains within the wheelhouse of state regulators and is not priced in the interstate wholesale market.[200]

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194 *Id.*

195 *See FERC Rejects PUCO-Approved FirstEnergy, AEP Power Deals*, THE PLAIN DEALER, April 28, 2016, online at http://www.cleveland.com/business/index.ssf/2016/04/ferc_rejects_puco_approval_of.html (describing FERC's rejection of monthly surcharges aimed at protecting existing coal and nuclear plants from competitive markets).

196 Hammond & Spence, *supra* note [22], at 209.

197 Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 961 (1986).

198 For further discussion, see Hammond & Spence, *supra* note [22], at 154.

199 *Hughes*, 136 S. Ct. at 1298.

200 Even where, as in PJM, capacity markets provide some reliability pricing in the wholesale market, it is not clear that they provide a perfect market valuation of reliability values associated with different energy resources. The American Public Power Association, for example, has highlighted how long-term contracts provide a superior way of promoting reliability in comparison to capacity markets, and that capacity markets can result in different reliability pricing based on how a state chooses to address its retail market. See *Staying Power of a Bad Idea: Capacity Markets' Reliability Pricing Mechanism*, online at http://blog.publicpower.org/sme/?p=761.

Still, two-thirds of electricity use in the United States takes place within the organized competitive markets. And absent any effective market price on carbon (such as a national carbon tax), regional initiatives (including PJM's capacity market) fail entirely to price the carbon attributes of various sources of energy.[201] As Justice Ginsburg wrote for the *Hughes* majority, "We reject Maryland's program only because it disregards an interstate wholesale rate required by FERC."[202] Although somewhat unclear, the majority seems to leave open state flexibility to adopt power supply incentives and subsidies that advance other values, beyond what is reflected in FERC-approved market prices.[203] Thus, regulatory measures that states utilize to promote clean power generation, especially those based on the carbon attributes of different energy resources, ought to be able to coexist with FERC's regulation of wholesale power markets.

Hughes therefore leaves states considerable space to endorse important regulatory values in the transition to a decarbonized grid where these values are not priced in the wholesale competitive power market regulated by FERC. In addressing stranded cost compensation for the risks associated with energy infrastructure, state regulators should be encouraged to approach new infrastructure with the aim of advancing values such as low carbon energy. Of course, as *Hughes* reminds us, such efforts cannot be motivated by or target a FERC-approved exclusive scheme for pricing wholesale power sales, such as the capacity market operated by PJM. However, to the extent that stranded cost recovery is aimed at social values that are not presently valued in competitive market prices as approved by FERC, such as retail reliability or carbon impacts of various energy resources, it is not inconsistent with *Hughes'* preemption analysis for states to provide incentives or subsidies to compensate these energy resources differently.

In a new experiment that will test this assertion and the limits of *Hughes*, the N.Y. Public Service Commission (NYPSC) has adopted a Clean Energy Standard that will among other things compensate upstate merchant nuclear power plants for the social cost of carbon that their electricity generation avoids.[204] Under the Zero Emission Credit approach applicable to these plants, the nuclear energy companies operating the relevant plants will receive payments equivalent to the social cost of carbon, netting out revenues from the Regional Greenhouse Gas Initiative (RGGI), for the first two-year period of the Credit.[205] This approach seems to fall on the "safe" side of *Hughes*, because it makes no reference to the wholesale markets and prices an attribute not considered on those markets. In later years, however, there will also be a price adjustment for wholesale

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201 Hammond & Spence, *supra* note [22], at 174.
202 *Hughes*, 136 S.Ct. at 1299.
203 Id. Justice Sotomayor's concurrence also underscored "the importance of protecting the States' ability to contribute, within their regulatory domain, to the Federal Power Act's goal of ensuring a sustainable supply of efficient and price-effective energy." Id. 1300 (Sotomayor, J., concurring).
204 N.Y. Clean Energy Standard, *supra* note [63], at 119-25. In adopting this approach, New York regulators rejected earlier proposals that were much more closely tied with wholesale revenues. *See* Joel Joel B. Eisen, *Dual Electricity Federalism Is Dead, But How Dead, and What Replaces It?*, -- GEO. WASH. J. ENERGY & ENV'T. – , manuscript at *37-38 (forthcoming 2016) (on file with authors).
205 N.Y. Clean Energy Standard, *supra* note [63], at 131.

energy and capacity market revenues.[206] Although the NYPSC was careful to note that it was not setting a price floor for nuclear power,[207] the fact that later compensation directly accounts for wholesale market revenues is at least worrisome under *Hughes*.[208]

Despite the uncertainties created by *Hughes*, we are optimistic about the general viability of stranded cost approaches in furtherance of grid decarbonization. That decarbonization is directed at a value not incorporated into the wholesale markets means states ought to be able to craft a variety of approaches without running afoul of *Hughes*. To the extent that federal involvement is necessary to address some stranded cost issues, we are encouraged that FERC has experience with such policies just as the states do.

CONCLUSION

Stranded cost recovery for investor risk has played a central role with energy industry transformation, often helping to grease the wheels of transition. However, as past experiments with stranded cost recovery show, it also has suffered from a myopia that has delayed some desirable industry transitions and left stranded important values that firms and energy markets fail to price. The impending transition to a decarbonizated grid cannot ignore these timing and stranded value issues and thus presents a unique opportunity to improve energy law's approach to stranded cost compensation. As in the past, stranded cost compensation will prove important (and we believe essential) to the next energy transition, but it can and should be approached in a manner that overcomes decarbonization's obstacles, reassures investors in new infrastructure without distorting price signals, and recognizes important energy resource attributes that markets fail to price.

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206 *Id.* at 138.
207 *Id.* at 139.
208 For further analysis, see Eisen, *supra* note 204, at 39-40.

IN THE DISTRICT COURT OF APPEAL
FIRST DISTRICT, STATE OF FLORIDA

STATE OF FLORIDA,

Appellant,

NOT FINAL UNTIL TIME EXPIRES TO
FILE MOTION FOR REHEARING AND
DISPOSITION THEREOF IF FILED

v.

CASE NO. 1D12-4106

STEPHEN D. BASFORD d/b/a
BASFORD FARMS,

Appellee.

_______________________________/

Opinion filed July 24, 2013.

An appeal from the Circuit Court for Jackson County.
John L. Fishel, II, Judge.

Pamela Jo Bondi, Attorney General, Jonathan Glogau, Special Counsel, and Rachel E. Nordby, Deputy Solicitor General, Tallahassee, for Appellant.

M. Stephen Turner, David K. Miller, and Gino A. Luzietti of Broad and Cassel, Tallahassee, for Appellee.

LEWIS, C.J.

Appellant, the State of Florida, seeks review of a Final Judgment awarding Appellee, Stephen D. Basford d/b/a Basford Farms, $505,000 plus interest for a taking of certain improvements on his real property as a result of article X, section

21 of the Florida Constitution, which is commonly referred to as the "Pregnant Pig Amendment." The State argues that the trial court erroneously ruled that Appellee's inverse condemnation claim was not barred by the four-year statute of limitations provided for in section 95.11(3)(p), Florida Statutes. It also contends that the trial court erred in finding a taking where the Amendment did not deprive Appellee of all reasonable and beneficial use of his real property. Finding no merit in either argument, we affirm.

The Amendment at issue, which makes it unlawful "for any person to confine a pig during pregnancy in an enclosure, or to tether a pig during pregnancy, on a farm in such a way that she is prevented from turning around freely," was approved by Florida voters in 2002 but did not take effect until 2008. As found by the trial court, Appellee ran a sophisticated mass pork production operation in which the animals were housed in barns at all times. Appellee, who was reportedly one of only two pig farmers in Florida using gestation crates when the Amendment was passed, placed certain improvements on his real property for his business. These improvements included a breeding barn, a gestation barn where the gestation crates that were banned by the Amendment were used, a farrowing barn with farrowing crates, two finishing barns, a feed mill and shelter equipped for storing and mixing feed, a lab/office with equipment for artificial insemination, four water wells with pumps to serve the barns and feed mill, clay lagoons for waste disposal, and a metal chute with hydraulic cylinders for lifting pigs into trailers for transport to market. Appellee's business depended on raising a high volume of pigs for market, and his improvements were designed for that purpose. Appellee shut down his business in 2003 after passage of the Amendment. According to Appellee, he could not, without the gestation crates, operate his business and compete with other producers who were not similarly restricted.

After shutting down his business, Appellee began raising perennial peanut hay on the tillable portion of his land. Appellee tore two barns down to the concrete slab and has built or is building new barns for his hay operation. The original barns could not be used for any purpose other than raising pigs because the eaves were too low. It was not possible to drive vehicles or equipment over the concrete flooring because of the gutters. The four-inch wells and 1,000 gallon tanks had no other practical use. Appellee was unable to lease the empty feed mill, and it had no other use. Through his local representatives, Appellee submitted a compensation claim for the loss of his business to the Legislature for 1.35 million dollars. Although appropriation bills were passed in 2004 and 2005, each was vetoed by the governor. In 2005 or 2006, Appellee sold for salvage value the gestation and farrowing crates, some concrete slats, and a heated nursery to a farmer in Georgia.

In January 2010, Appellee filed a complaint against the State for inverse condemnation and for compensation under the Bert J. Harris, Jr. Private Property Rights Protection Act. Appellee argued that the Amendment deprived him of all economically viable and reasonable use of his business for a pubic purpose. The trial court granted the State's summary judgment motion as to the second count of the complaint based upon Appellee's failure to satisfy presuit notice requirements but denied the motion as to the inverse condemnation claim.

During the bench trial on the inverse condemnation claim, Appellee's counsel explained that Appellee was not seeking any value for the land itself but was seeking the value of the improvements and the fixtures that he used in his pork production business. Counsel argued that the taking occurred in November 2008, when the Amendment took effect. The State's counsel argued that Appellee's cause of action accrued in 2003 when he voluntarily shut down his operation. Appellee testified that it was too expensive to rebuild the improvements for a pen-raising pig operation or to convert them for other farming operations. He estimated that it would cost $600,000 to convert to a pen-raising operation. Tim Hewitt, a former extension agent who testified by deposition, believed it would not be feasible for Appellee to stay in business if he was going to have to stop using gestation crates and substantially change his operation. After hearing arguments, the trial court stated in part that a takings analysis under <u>Penn Central</u>

Transportation Co. v. City of New York, 438 U.S. 104 (1978), "has to take into consideration everything."

In the Order of Liability on Partial Taking, the trial court noted that takings claims are either categorical in nature or as-applied. It determined that no categorical taking of Appellee's property occurred because although the Amendment substantially impacted his ability to generate income from his business, the remainder of his property continued to generate income from crops. The trial court noted that under the analysis set forth in Penn Central Transportation Co., the test for an as-applied or regulatory taking requires consideration of three factors: (1) the regulation's economic impact on the claimant; (2) the regulation's interference with distinct investment-backed expectations; and (3) the character of the governmental action.

Focusing on Appellee's improvements, the trial court found that there was a substantial reduction in their market value as a result of the Amendment and that the Amendment interfered with Appellee's reasonable investment-backed expectations. In finding that the purpose of the Amendment was to prevent a public harm, the trial court concluded that the Amendment resulted in an as-applied or regulatory taking of Appellee's improvements. The trial court found that the taking occurred on November 5, 2008, the effective date of the Amendment, and that the statute of limitations began to run at that time. It determined that Appellee was entitled to recover the fair market value of the improvements valued at the time of the taking less salvage value. Although noting that the Amendment restricted only the use of gestation crates, the trial court found that the Amendment resulted in the taking of all of the improvements due to their "functionally integrated nature." The trial court further concluded that Appellee's business damages and his losses incurred in selling his breeding stock were not compensable. Thereafter, the trial court entered a Final Judgment wherein it ordered, pursuant to the parties' stipulation as to the value of the property taken, that Appellee was entitled to $505,000 plus interest. This appeal followed.

The State first argues that the trial court erroneously ruled that Appellee's inverse condemnation claim was not barred by the four-year statute of limitations provided for in section 95.11(3)(p). However, contrary to the State's argument that any taking occurred in 2002 when the Amendment was passed or in 2003 when Appellee shut down his business, the government had no enforcement authority to prohibit the use of gestation crates prior to the Amendment's effective date in 2008. We, therefore, agree with the trial court that Appellee's inverse condemnation claim accrued in November 2008. See Lamar Whiteco Outdoor Corp. v. City of W. Chicago, 823 N.E.2d 610, 624 (Ill. App. Ct. 2005) (holding that the statute of limitations pertaining to the appellants' challenge to a zoning ordinance that banned certain commercial and noncommercial off-premises advertising structures did not begin to run until a seven-year grace period expired because the ordinance did not affect the appellants' right to display the billboards in their original state during the grace period).

The State also contends on appeal that the trial court erred in finding an as-applied taking of Appellee's improvements. Article X, section 6(a) of the Florida Constitution provides that "[n]o private property shall be taken except for a public purpose and with full compensation therefor paid to each owner or secured by deposit in the registry of the court and available to the owner." The standard of proof for an as-applied taking is whether there has been a substantial deprivation of economic use or reasonable investment-backed expectations. Shands v. City of Marathon, 999 So. 2d 718, 723 (Fla. 3d DCA 2008). This requires a "'fact-intensive inquiry of impact of the regulation on the economic viability of the landowner's property by analyzing permissible uses before and after enactment of the regulation.'" Id. (citation omitted). When reviewing this issue, the trial court's factual findings are afforded deference while its application of the facts to the law is reviewed de novo. See USA Independence Mobilehome Sales, Inc. v. City of Lake City, 908 So. 2d 1151 (Fla. 1st DCA 2005); see also Dep't of Transp. v. Fisher, 958 So. 2d 586 (Fla. 2d DCA 2007).

While the State argues that the trial court erred in analyzing Appellee's improvements without considering his overall farming business, the record establishes that the trial court was very much aware of the fact that Appellee continued to raise crops on his property. The trial court noted during the bench trial that a Penn Central analysis has to "take into consideration everything." The trial court further noted that Appellee was not seeking compensation for any diminution in the value of his land and only alleged a taking of his business. It is also important to consider that the trial court labeled its order finding a taking as an "Order of Liability on Partial Taking." See Res. Invs., Inc. v. United States, 85 Fed. Cl. 447, 477 (Fed. Cl. 2009) ("If the taking is not of the *entire* parcel as a whole, either temporally or by its metes and bounds, government regulation can still effect a *partial* taking pursuant to the fact intensive *Penn Central* balancing test.") (Emphasis in original). Another important consideration, which neither the State nor the dissent acknowledges, is that real property, tangible property, and intangible property may be the subject of a takings claim. See Acceptance Ins. Cos. v. United States., 583 F.3d 849, 854 (Fed. Cir. 2009); see also Yancey v. United States, 915 F.2d 1534, 1541 (Fed. Cir. 1990) ("For Fifth Amendment purposes, the [plaintiffs'] ownership of their turkey flock deserves just as much protection as if ownership of their farm had been appropriated."); Dep't of Agric. & Consumer Servs. v. Mid-Fla. Growers, Inc., 521 So. 2d 101, 102-05 (Fla. 1988) (holding that a taking occurred when the State burned the respondents' healthy citrus trees as a result of a concern over citrus canker). Contrary to the State's characterization of this case as an alleged taking of real property, Appellee did not allege a taking of his land. As such, under the facts of this case, we reject the State's argument that no taking could have occurred because the underlying real property was capable of being used for other purposes.

In determining that an as-applied taking occurred as a result of the Amendment, the trial court accepted Appellee's testimony that his barns could not be used for any purpose other than raising pigs and that the wells and feed mill had no other practical purpose or use. The State offered no evidence below to refute Appellee's testimony on alternative uses of the improvements. Nor has it argued on appeal that the improvements had any other purpose or that Appellee could have converted to a pen-raising pig operation. Cf. Schreiner Farms, Inc. v. Smitch, 940 P.2d 274, 278 n.12 (Wash. Ct. App. 1997) (holding that the regulation at issue did not effect a taking of the appellant's elk herd and noting that the appellant's special fencing, well, elk-handling facility, and irrigation system had not been rendered worthless by the regulation at issue because they could be used to raise other animals on the ranch). Although the Amendment only restricted the use of gestation crates, a fact which the trial court acknowledged, the court found that the other improvements were functionally integrated with the crates. The State does not challenge this finding on appeal either. As such, we are bound by the trial court's factual findings as to the value, or lack thereof, of Appellee's improvements as a result of the Amendment and, therefore, affirm the Final Judgment. In doing so, we note that our opinion should in no way be viewed as an expansion of rights under article X, section 6(a) of Florida's Constitution. Our disposition is based solely upon the record in this case, the issues that were developed below, and the arguments that were raised by the State on appeal.

AFFIRMED.

WOLF, J., CONCURRING WITH OPINION; PADOVANO, J., DISSENTING WITH OPINION.

WOLF, J., Concurring.

I concur in the well-reasoned opinion of Judge Lewis. I write for two reasons: (1) to point out important factual distinctions between this case and Penn Central Transportation Co. v. City of New York, 438 U.S. 104 (1978); and (2) to reiterate Judge Lewis' point that this is a very limited decision based on the trial court's findings that the items of property for which appellee is receiving compensation have absolutely no reasonable purpose, use, or value after application of the "pregnant pig amendment."

In Penn Central, the claim of the property owner related to the value of land and its future development rights. 438 U.S. at 118-19. The land at issue still had alternative uses and retained much of its value. Id. at 118-19, 129-38. In this case the claim is not for diminution of value of land or loss of business profits. Appellant's damage claim is for tangible property and improvements which had lost all value because of governmental regulation.

In Penn Central, the assessment concerning the land involved a bundle of property rights associated with the land. Id. at 129-38. No such bundle of rights exists in the tangible property at issue in this case. It cannot reasonably be argued that the State could come onto a farmer's property and take a tractor and not be required to pay for it. I see no practical difference between the seizure of a tractor and the government telling a tractor owner that the owner can keep the tractor but under no circumstances can the owner turn it on. I also do not see a valid argument that a property owner should not be compensated for costly improvements on property that are rendered valueless because they may be designated fixture.[*]

I would also note, absent the trial court's finding in this case that there was "no" remaining practical use of the property in question (a result I am skeptical of but, because the State presented no competent evidence in this regard and because the trial court's findings are supported by competent substantial evidence, is one we must honor), there would be no recovery. Under the limited circumstances in this case, upholding the damage award is appropriate.

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[*] Because there is no claim based on the lost value and business damages are unavailable, there is no issue concerning duplicative recovery.

PADOVANO, J., dissenting

I acknowledge that the plaintiff's breeding barn was uniquely designed to house pigs in gestation crates and that it was rendered useless after the passage of the Article X, section 21. However, the breeding barn was only a small part of the plaintiff's real property. In fact, the plaintiff's entire pork production operation took place on only four acres of his three hundred and eighteen acre farm. The loss of the barn may have diminished the value of the farm but that is not enough to support a "taking" claim.

The Fifth Amendment protection against the taking of property without just compensation ensures that the government will not force only some people to bear public burdens that in all fairness should be shared by the public as a whole. See Armstrong v. United States, 364 U.S. 40, 49 (1960). It does not ensure that the government will provide compensation merely because the passage of a new law has an adverse economic interest on an existing property right. As the Supreme Court explained in Penn Central Transportation Company v. City of New York, 438 U.S. 104, 124 (1978) (quotation omitted), "[g]overnment hardly could go on if to some extent values incident to property could not be diminished without paying for every such change in the general law.'"

The fallacy of the plaintiff's argument in this case is that it attempts to separate the breeding barn from the rest of the real property. If that could be done, I would agree that the passage of Article X, section 21 resulted in a constructive taking of his property. But it cannot be done. We are obligated to evaluate the plaintiff's claim based on the effect this new constitutional provision had on the entire parcel of land, not just one structure on the land, or several acres of the land. The Supreme Court made this point clear in Penn Central when it observed:

> "Taking" jurisprudence does not divide a single parcel into discrete segments and attempt to determine whether rights in a particular segment have been entirely abrogated. In deciding whether a particular governmental action has effected a taking, this Court focuses rather both on the character of the action and on the nature and extent of the interference with right in the parcel as a whole.

Penn Central, 438 U.S. at 130-131. The plaintiff's farm may be worth less now than it was before and perhaps it could be said that it can no longer be put to its highest and best use. Nevertheless, as I read the Penn Central line of cases, consequences such as these do not rise to the level of a governmental taking.

For these reasons, I respectfully dissent.

ORIGINAL

SCANNED

RUTLEDGE, ECENIA, PURNELL & HOFFMAN

PROFESSIONAL ASSOCIATION
ATTORNEYS AND COUNSELORS AT LAW

STEPHEN A. ECENIA
RICHARD M. ELLIS
KENNETH A. HOFFMAN
LORENA A. HOLLEY
MICHAEL G. MAIDA
MARTIN P. McDONNELL
J. STEPHEN MENTON

POST OFFICE BOX 551, 32302-0551
215 SOUTH MONROE STREET, SUITE 420
TALLAHASSEE, FLORIDA 32301-1841

TELEPHONE (850) 681-6788
TELECOPIER (850) 681-6515

R. DAVID PRESCOTT
HAROLD F. X. PURNELL
MARSHA E. RULE
GARY R. RUTLEDGE
MAGGIE M. SCHULTZ

GOVERNMENTAL CONSULTANTS
MARGARET A. MENDUNI
M. LANE STEPHENS

January 27, 2006

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Ms. Blanca S. Bayó, Director
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

Re: Docket No. 020233-EI

Dear Ms. Bayó:

Enclosed for filing on behalf of GridFlorida Companies are the original and fifteen copies of the GridFlorida Companies' Motion to Withdraw Compliance Filing and Petition and Close Docket.

Please acknowledge receipt of these documents by stamping the extra copy of this letter "filed" and returning the copy to me. Please contact me if you have questions regarding this filing.

Thank you for your assistance with this filing.

Sincerely,

Kenneth A. Hoffman

KAH/rl
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of GridFlorida Regional Transmission Organization (RTO) Proposal	))))	Docket No. 020233-EI Filed: January 27, 2006

GRIDFLORIDA COMPANIES' MOTION TO WITHDRAW COMPLIANCE FILING AND PETITION AND CLOSE DOCKET

Florida Power & Light Company ("FPL"), Progress Energy Florida ("PEF") and Tampa Electric Company ("TECO") (hereinafter referred to collectively as the "GridFlorida Companies"), by and through undersigned counsel, hereby move to withdraw the Compliance Filing filed on March 20-21, 2002 and the September 19, 2002 Petition of the GridFlorida Companies regarding Prudence of GridFlorida Market Design Principles, and request that the Florida Public Service Commission ("Commission" or "FPSC") close the above-styled docket. In support of this Motion, the GridFlorida Companies state as follows:

1. On October 16, 2000, pursuant to Federal Energy Regulatory Commission ("FERC") Order No. 2000, FPL, PEF's predecessor, Florida Power Corporation ("FPC") and TECO filed a Joint Compliance Filing with FERC concerning the establishment of the GridFlorida Regional Transmission Organization ("RTO"). The October 16, 2000 filing requested an expedited ruling on the governance and independence aspects of the GridFlorida RTO proposal.

2. On December 15, 2000, the GridFlorida Companies submitted a Supplemental Filing with FERC incorporating the pricing, market design, operations and planning protocols, and market monitor company incorporation documents and tariff.

3. On January 10, 2001, FERC issued a limited ruling addressing the governance and independence aspects of the GridFlorida RTO proposal. On March 28, 2001, FERC granted provisional approval of GridFlorida requiring GridFlorida to make a compliance filing within sixty days, including a revised market design and progress reports on negotiations with public entities for their participation in GridFlorida. See GridFlorida, LLC, 94 FERC ¶ 61,020 (2001) ("GridFlorida I"); GridFlorida, LLC, 94 FERC ¶ 61,363 ("GridFlorida II"), order on reh'g, 95 FERC ¶ 61,473 (2001).

4. On May 29, 2001, in Docket Nos. 000824-EI, 001148-EI and 010577-EI, the FPSC voted to require each GridFlorida Company to file a petition to determine the prudence of their formation and participation in GridFlorida.

5. On that same day, May 29, 2001, the GridFlorida Companies submitted a compliance filing with FERC pursuant to FERC's March 28, 2001 Order. The GridFlorida Companies notified FERC of the status of various aspects of GridFlorida, including the formal prudence investigation initiated by the FPSC regarding participation in GridFlorida.

6. On June 12, 2001, each GridFlorida Company filed a Petition to Determine the Prudence of Formation of and Participation in GridFlorida, LLC.

7. On December 20, 2001, the Commission issued Order No. PSC-01-2489-FOF-EI ("Order No. 01-2489") finding the proactive formation of GridFlorida prudent and requiring the filing of a modified GridFlorida proposal. Order No. 01-2489 held, in pertinent part, that: (a) the GridFlorida Companies were prudent in proactively forming GridFlorida (see Order at 4); (b)

GridFlorida initially should be structured as an independent system operator ("ISO") rather than a transmission-owning company (see id. at 12); and (c) GridFlorida must use the "get what you bid" market approach as part of the market design for GridFlorida (see id. at 20-23).

8. On March 13, 2002, the above-captioned docket was opened and, thereafter, on March 20-21, 2002, the GridFlorida Companies filed a Modified GridFlorida Proposal pursuant to and in compliance with Order No. 01-2489 (the "Compliance Filing"). The Compliance Filing amended the original GridFlorida proposal in four basic ways. First, GridFlorida was changed from a for-profit transco to a non-profit ISO. Second, subject to one exception, at a transmission customer's option, that customer's bundled retail load would be exempt from zonal transmission charges under the GridFlorida transmission tariff for a five year transition period.[1] Third, the Compliance Filing incorporated a "get what you bid" approach for balancing energy and redispatch. Fourth, the GridFlorida planning process was revised to make it more compatible with the ISO structure ordered by the Commission.

9. On May 29, 2002, the Commission held a workshop to address various issues regarding the GridFlorida Companies' Compliance Filing. As a result of that workshop, analysis of stakeholder comments at the workshop, and additional deliberations, the GridFlorida Companies proposed to amend the market design filed as part of their Compliance Filing.

10. On July 2, 2002, the GridFlorida Companies proposed to amend certain aspects of the market design filed with the Commission as part of the Compliance Filing by proposing the use of: (a) a locational marginal pricing model, i.e., a financial transmission rights ("FTRs") model with locational or nodal pricing, rather than a physical transmission rights model, for

[1]The GridFlorida Companies indicated in the Compliance Filing that they would choose to exempt bundled retail load.

congestion management and energy markets; (b) a two-tier settlement system consisting of a voluntary day-ahead market and a real-time market; and (c) payments of market clearing prices calculated on a nodal basis rather than the "get what you bid" approach included in the Compliance Filing.

11. On September 3, 2002, the Commission issued Order No. PSC-02-1199-PAA-EI ("Order No. 02-1199") which ruled in part on the GridFlorida Companies' compliance with Order No. 01-2489, requiring an evidentiary hearing to address the merits of the revised GridFlorida market design proposal, and set forth proposed agency action determinations regarding specific changes to the GridFlorida Compliance Filing.

12. On September 19, 2002, the GridFlorida Companies filed their Petition and supporting testimony addressing their proposed changes for the GridFlorida market design. The September 19, 2002 Petition requested the Commission to determine that it was prudent for the GridFlorida Companies to develop detailed market design rules and a transmission tariff that would implement: (a) FTRs and locational marginal pricing for congestion management and energy markets; (b) a voluntary day-ahead market and a real-time market; (c) payments of market clearing prices calculated on a "nodal" basis; (d) mechanisms to ensure resource adequacy; (e) allocation of FTRs; (f) market power mitigation measures; and (g) a hierarchical control system.[2]

13. Protests to various proposed agency action determinations and motions for reconsideration of various final agency action determinations of the Commission were filed following the issuance of Order No. 02-1199. In addition, the Office of Public Counsel ("OPC") filed an appeal of Order No. 02-1199 triggering an automatic stay.

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[2]On October 7, 2002, the GridFlorida Companies filed a Motion for Leave to File Amended Petition and Proposed Amended Petition to Remove Hierarchical Control Areas as a Component of the New Market Design as such had already been approved by the Commission.

14. On July 8, 2003, the Supreme Court of Florida issued an Order dismissing OPC's appeal without prejudice to any party to bring a challenge to Order No. 02-1199 after all portions are final. See Citizens v. Jaber, 847 So.2d 975 (Fla. 2003).

15. On September 8, 2003, the Commission issued Order No. PSC-03-1006-FOF-EI resolving the outstanding motions for reconsideration of Order No. 02-1199.

16. In November 2003, the GridFlorida Companies announced that they had retained ICF Consulting Resources, LLC ("ICF") to conduct a cost/benefit analysis of the revised market design and GridFlorida RTO structure to determine the level of costs and benefits that could be expected from its formation.

17. On December 15, 2003, Order No. PSC-03-1414-PCO-EI was issued scheduling new workshops and the submissions of comments and positions to address pending issues in the areas of pricing and market design, along with a wrap-up workshop. On January 15, 2004, Staff submitted a list of issues to be addressed at the pricing workshop including the "[c]ontinued review of RTO costs and benefits."

18. Following the two scheduled pricing and market design workshops, a third workshop was held on June 30, 2004 before the full Commission for the purpose of gathering input from interested persons regarding the cost-benefit analysis of GridFlorida being conducted by ICF and to discuss the project's proposed assumptions.

19. On December 12, 2005, ICF issued its final report entitled "Cost-Benefit Study of the Proposed GridFlorida RTO," a copy of which is attached hereto as Exhibit A. The ICF Study clearly demonstrates that the GridFlorida RTO, whether modeled as a Day 1 or Delayed Day 2 proposal, is not cost beneficial for the retail customers of the GridFlorida Companies. As stated in the "Summary of Conclusions" section on page 149 of the Report:

> ICF's analysis shows that the quantitative benefits of a Delayed Day-2 RTO operation are significant, and range from \$810 million to \$968 million in the scenarios in this study. However, the cost of a "greenfield" Delayed Day-2 RTO with wholly new systems, physical facilities and personnel, designed along FERC's Standard Market Design principles, is also very significant at \$1.25 billion. The prospects of a Day-1 RTO are bleak, especially if designed along a "greenfield" RTO with wholly new systems, personnel and physical facilities, because the benefits of a Day-1 RTO operation are not nearly as large as a Delayed Day-2 RTO operation, while the fixed costs are high.

20. In light of the findings and conclusions of the final ICF Study, the GridFlorida Companies submit that it is no longer prudent to pursue implementation of the GridFlorida RTO. Accordingly, the GridFlorida Companies maintain that it is in the best interests of their retail customers that the Commission approve the withdrawal of the GridFlorida Companies' Compliance Filing and September 19, 2002 Petition and that this docket be closed.

WHEREFORE, for the foregoing reasons, the GridFlorida Companies respectfully request that the Commission enter a Final Order approving:

A. The Withdrawal of the GridFlorida Companies' Compliance Filing filed on March 20-21, 2002;

B. The withdrawal of the GridFlorida Companies' Petition regarding Prudence of GridFlorida market design principles filed on September 19, 2002; and

C. The closure of the above-referenced docket.

Respectfully submitted,

R. WADE LITCHFIELD, ESQ.
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 32408-0420
Tel: (561) 691-7101
Fax: (561) 691-7135

KENNETH A. HOFFMAN, ESQ.
Rutledge, Ecenia, Purnell & Hoffman, P.A.
Post Office Box 551
Tallahassee, FL 32302
Tel: (850) 681-6788
Fax: (850) 681-6515
On behalf of Florida Power & Light Company

LEE L. WILLIS, ESQ.
JAMES D. BEASLEY, ESQ.
Ausley & McMullen
Post Office Box 391
Tallahassee, FL 32302
Tel: (850) 224-9115
Fax: (850) 222-7952
On behalf of Tampa Electric Company

JOHN BURNETT, ESQ.
Florida Power Corporation
Post Office Box 14042
St. Petersburg, FL 33733
Tel: (727) 820-5185
Fax: (727) 820-5519
On behalf of Florida Power Corporation

By: ______________________
Kenneth A. Hoffman, Esq.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the GridFlorida Companies' Motion to Withdraw Compliance Filing/Petition and Close Docket has been furnished by Electronic Mail, this 27th day of January, 2006, to the following:

FLORIDA PUBLIC SERVICE COMMISSION

William Cochran Keating, IV
Jennifer S. Brubaker
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
Ph: 850-413-6193
Fax: 850-413-6194
e-mail:wkeating@psc.state.fl.us
jbrubake@psc.state.fl.us

OFFICE OF PUBLIC COUNSEL

Office of Public Counsel
Jack Shreve/J. Roger Howe
111 W. Madison Street, #812
Tallahassee, FL 32399-1400
Ph: 850-488-9330
Fax: 850-488-4491
e-mail: howe.roger@leg.state.fl.us

TAMPA ELECTRIC COMPANY

Lee L. Willis
James D. Beasley
Ausley & McMullen
Post Office Box 391
Tallahassee, FL 32302
Ph: 850-224-9115
Fax: 850-222-7952
e-mail: lwillis@ausley.com
jbeasley@ausley.com
Attorneys for Tampa Electric Company

Tampa Electric Company
Angela Llewellyn
Regulatory Affairs
Post Office Box 111
Tampa, FL 33601-0111
Ph: 813-228-1752
Fax: 813-228-1770
e-mail: alllewellyn@tecoenergy.com

FLORIDA POWER CORPORATION

Florida Power Corporation
John Burnett, Esquire
Post Office Box 14042
St. Petersburg, FL 33733
Ph: 727-820-5184
Fax: 727-820-5519
e-mail: john.burnett@pgn.com
Attorney for Florida Power Corporation

David Goroff
Peter K. Matt
Bruder, Gentile & Marcoux, L.L.P.
1100 New York Avenue, N.W.
Suite 510-East
Washington, D.C. 20005-3934
Ph: 202-783-1350
Fax: 202-737-9117
e-mail: degoroff@brudergentile.com
Attorneys for Florida Power Corporation

Florida Power Corporation
Paul Lewis, Jr.
106 East College Avenue, Suite 800
Tallahassee, FL 32301-7740
Ph: 850-222-8738, 727-820-5184
Fax: 850-222-9768
e-mail: paul.lewisjr@pgnmail.com

FLORIDA POWER & LIGHT CO.

Rutledge Law Firm
Kenneth Hoffman
Post Office Box 551
Tallahassee, FL 32301
Ph: 850-681-6788
Fax: 850-681-6515
e-mail: ken@reuphlaw.com
Attorneys for Florida Power & Light Co.

Bill Walker
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1859
Ph: 850-521-3900
Fax: 850-521-3939
e-mail: bill_walker@fpl.com

R. Wade Litchfield, Esq.
Law Department
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0429
Ph: 561-691-7101
Fax: 561-691-7135
e-mail: wade_litchfield@fpl.com

CALPINE CORPORATION
DUKE ENERGY NORTH AMERICA
MIRANT AMERICAS DEVELOPMENT INC.

Leslie J. Paugh, P.A.
Post Office Box 16069
Tallahassee, FL 32317-6069
Ph: 850-656-3411
Fax: 850-656-7040
e-mail: lpaugh@paugh-law.com
Attorneys for Calpine Corporation,
Mirant Americas Development, Inc.
Duke Energy North America
Calpine Corporation

Thomas W. Kaslow
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110
Ph: 617-723-7200, ex. 393
Fax: 617-557-5353
e-mail: tkaslow@calpine.com

Duke Energy North America
Lee E. Barrett
5400 Westheimer Court
Houston, TX 77056-5310
Ph: 713-627-6519
Fax: 713-627-6566
e-mail: lebarrett@duke-energy.com

Mirant Americas Development, Inc.
Beth Bradley
1155 Perimeter Center West
Atlanta, GA 30338-5416
Ph: 678-579-3055
Fax: 678-579-5819
e-mail: beth.bradley@mirant.com

DYNEGY INC., PUBLIX,
ORLANDO UTILITIES COMMISSION

Gray, Harris & Robinson, P.A. (Orl)
Thomas Cloud/W.C. Browder/P. Antonacci
301 East Pine Street, Suite 1400
Orlando, FL 32801
Ph:407-244-5624, 407-843-8880
Fax: 407-244-5690
e-mail: tcloud@grayharris.com
cbrowder@grayharris.com
Attorneys for Dynegy, Publix and OUC

Orlando Utilities Commission
Wayne Morris/Thomas Washburn
Post Office Box 3193
Orlando, FL 32802-3193
Ph: 407-423-9100, 407-384-4066
Fax: 407-423-9198
e-mail: twashburn@ouc.com
Dynegy Inc.

David L. Cruthirds
1000 Louisiana Street, Suite 5800
Houston, TX 77002-5050
Ph: 713-507-6785
Fax: 713-507-6834
e-mail: david.cruthirds@dynegy.com

Publix Super Markets, Inc.
John Attaway
Post Office Box 32015
Lakeland, FL 33802-2018
Ph: 863-686-8754
Fax: 863-616-5704
e-mail: johnattaway@mail.publix.com

SEMINOLE ELECTRIC COOPERATIVE, INC. SEMINOLE MEMBER SYSTEMS

Foley & Lardner Law Firm
Thomas J. Maida/N. Wes Strickland
106 East College Ave., Suite 900
Tallahassee, FL 32301-3369
Ph: 850-222-6100, 850-513-3369
Fax: 850-224-3101
e-mail: tmaida@foleylaw.com
nstrickland@foleylaw.com
Attorneys for Seminole Electric Coop.

William T. Miller
Miller Law Firm
1140 19th St., NW, Suite 700
Washington, DC 20036
Ph: 202-296-2960
Fax: 202-296-0166
e-mail: wmiller@mbolaw.com
Attorneys for Seminole Electric Cooperative, Inc.

Seminole Electric Cooperative, Inc.
Timothy Woodbury
16313 North Dale Mabry Highway
Tampa, FL 33688-2000
Ph: 813-963-0994
Fax: 813-264-7906
e-mail: twoodbury@seminole-electric.com

FLORIDA ELECTRIC COOPERATIVES ASSOC., INC.
Michelle Hershel
2916 Apalachee Parkway
Tallahassee, FL 32301
Ph: 850-877-6166
Fax: 850-656-5485
e-mail: mhershel@feca.com

CPV ATLANTIC, LTD., PG&E NATIONAL ENERGY GROUP CO.

Jon Moyle/Cathy Sellers/Dan Doorakian
Moyle Law Firm
The Perkins House, 118 N Gadsden St.
Tallahassee, FL 32301
Ph: 850-681-3828
Fax: 850-681-8788
e-mail: jmoylejr@moylelaw.com
Attorneys for CPV Atlantic, Inc.
PG&E National Energy Group Co.

CPV Atlantic, Ltd.
146 NW Central Park Plaza, Suite 101
Port Saint Lucie, FL 34986

PG&E National Energy Group Co.
Melissa Lavinson
7500 Old Georgetown Road
Bethesda, MD 20814
Ph: 301-280-6887
Fax: 301-280-6379
e-mail: melissa.lavinson@neg.pge.com

RELIANT ENERGY POWER GENERATION, INC.
McWhirter Law Firm
Vicki Kaufman/Joseph McGlothlin
117 S. Gadsden Street
Tallahassee, FL 32301
Ph: 850-222-2525
Fax: 850-222-5606
e-mail: jmcglothlin@mac-law.com
vkaufman@mac-law.com
Attorneys for Reliant Energy Power Generation, Inc.

Reliant Energy Power Generation, Inc.
Michael Briggs
801 Pennsylvania Ave., Suite 620
Washington, DC 20004
Ph: 202-783-7220
Fax: 202-783-8127
e-mail: mbriggs@reliant.com

FLORIDA INDUSTRIAL POWER USERS GROUP

McWhirter Law Firm
John McWhirter
Post Office Box 3350
Tampa, FL 33601-3350
Ph: 813-224-0866
Fax: 813-221-1854
e-mail: jmcwhirter@mac-law.com
Attorneys for Florida Industrial Power Users Group

REEDY CREEK IMPROVEMENT DISTRICT
WALT DISNEY WORLD

Sutherland Asbill & Brennan LLP
Daniel Frank
1275 Pennsylvania Ave., NW
Washington, DC 20004-2415
Ph: 202-383-0838, 202-383-0100
Fax: 202-637-3593
e-mail: dfrank@sablaw.com
Attorneys for Reedy Creek and Walt Disney World

John Giddens
Reedy Creek Improvement District
Post Office Box 10000
Lake Buena Vista, FL 32830
Ph: 407-824-4892
Fax: 407-824-5396
e-mail: john.giddens@disney.com

Lee Schmudde
1375 Lake Buena Drive
Fourth Floor North
Lake Buena Vista, FL 32830

FLORIDA MUNICIPAL POWER AGENCY
Frederick M. Bryant/Jody Lamar Finklea
2061-2 Delta Way
Tallahassee, FL 32303
Ph: 850-297-2011
Fax: 850-297-2014
e-mail: fred.bryant@fmpa.com
jody.lamar.finklea@fmpa.com
Attorneys for Florida Municipal Power Agency

Spiegel & McDiarmid
Cynthia Bogorad/David Pomper/J. Schwarz
1350 New York Ave., NW, Suite 1100
Washington, DC 20005-4798
Ph: 202-879-4000
Fax: 202-393-2866
e-mail: cynthia.bogorad@spiegelmcd.com
Co-counsel for Florida Municipal Power Agency

Florida Municipal Power Agency
Robert C. Williams
8553 Commodity Circle
Orlando, FL 32819-9002
Ph: 407-355-7767
Fax: 407-355-5794
e-mail: bob.williams@fmpa.com

CITY OF TALLAHASSEE
LAKELAND ELECTRIC
GAINESVILLE/KISSIMMEE

John & Hengerer Law Firm
Douglas John/Matthew Rick
1200 17th Street, NW
Suite 600
Washington, DC 20036-3013
Ph: 202-429-8801, 202-429-8809
Fax: 202-429-8805
e-mail: djohn@jhenergy.com
mrick@jhenergy.com
Attorneys for City of Tallahassee, Lakeland Electric, Gainesville and Kissimmee
City of Tallahassee
Pete Koikos
100 West Virginia Street
Fifth Floor
Tallahassee, FL 32301
Ph: 850-891-6893
Fax: 850-891-6890
e-mail: koikosp@talgov.com

City of Tallahassee
Paul Clark
400 East Van Buren Street
Fifth Floor
Tallahassee, FL 32301
Ph: 850-891-3130
Fax: 850-891-3138
e-mail: clarkp@talgov.com

Gainesville Regional Utilities/
City of Gainesville
Ed Regan
Post Office Box 147117, Station A136
Gainesville, FL 32614-7117
Ph: 352-334-1272, 352-334-3400x1260
Fax: 352-334-3151
e-mail: reganej@gru.com

Kissimmee Utility Authority
Robert Miller
1701 West Carroll Street
Kissimmee, FL 32746
Ph: 407-933-7777
Fax: 407-847-0787
e-mail: rmiller@kua.com

Lakeland Electric
Paul Elwing
501 E. Lemon Street
Lakeland, FL 33801-5079
Ph: 863-834-6531
Fax: 863-834-6362
e-mail: paul.elwing@lakelandgov.net

JACKSONVILLE ELECTRIC AUTHORITY

Suzanne Brownless, P.A.
1975 Buford Blvd.
Tallahassee, FL 32308-4466
Ph: 850-877-5200
Fax: 850-878-0090
e-mail: sbrownless@comcast.net
Attorney for JEA

P. G. Para
21 West Church Street
Jacksonville, FL 32202-3139
Ph: 904-665-6208
Fax: 904-665-4238
e-mail: parapg@jea.com

Dick Basford & Associates, Inc.
5616 Fort Sumter Road
Jacksonville, FL 32210
Ph: 904-771-3575
Fax: 573-7971
e-mail: dbasford@attbi.com

Michael Wedner
117 West Duval Street, Suite 480
Jacksonville, FL 32202
Ph: 904-630-1834
Fax: 904-630-1316
e-mail: mwedner@coj.net

SOUTH FLORIDA HOSPITAL and HEALTHCARE ASSOCIATION

Mark Sundback/Kenneth Wiseman
Andrews & Kurth Law Firm
1701 Pennsylvania Ave., NW, Suite 300
Washington, DC 20006
Ph: 202-662-2700
Fax: 202-662-2739
e-mail: msundback@andrews-kurth.com
Attorneys for South Florida Hospital and Healthcare Association

South Florida Hospital and Healthcare Association
Linda Quick
6363 Taft Street
Hollywood, FL 33024
Ph: 954-964-1660
Fax: 954-962-1260
e-mail: lquick@sfhha.com

FLORIDA RETAIL FEDERATION

Greenberg, Traurig Law Firm
Ron LaFace/Seann M. Frazier
101 E. College Ave.
Tallahassee, FL 32301
Ph: 850-222-6891
Fax: 850-681-0207
e-mail: lafacer@gtlaw.com
fraziers@gtlaw.com
Attorneys for Florida Retail Federation

Florida Retail Federation
100 E. Jefferson Street
Tallahassee, FL 32301
Ph: 850-222-3461
Fax: none
e-mail: bkelley@scholarship.org

TRANS-ELECT, INC.

Katz, Kutter Law firm
Bill Bryant, Jr./Natalie Futch
12th Floor
106 East College Avenue
Tallahassee, FL 32301
Ph: 850-224-9634
Fax: 850-222-0103
e-mail: natalief@katzlaw.com
Attorneys for Trans-Elect, Inc.

Trans-Elect, Inc.
Alan J. Statman, General Counsel
1200 G Street NW, Suite 600
Washington, DC 20005
Ph: 202-393-1200
Fax: 202-393-1240
e-mail: statman@wrightlaw.com

SOLID WASTE AUTHORITY OF PALM BEACH COUNTY
FLORIDA PHOSPHATE COUNCIL
FLORIDA INDUSTRIAL COGENERATION ASSOC.

Richard Zambo
598 SW Hidden River Ave.
Palm City, FL 34990
Ph: 772-220-9163
Fax: 772-220-9402
e-mail: richzambo@aol.com
Attorney for Solid Waste Authority
Florida Phosphate Council
Florida Industrial Cogeneration Assoc.

Solid Waste Authority
Dr. Marc C. Bruner
7501 North Jog Road
West Palm Beach, FL 33412
Ph: 561-640-4000, ex. 5607
Fax: 561-640-3400
e-mail: mcbruner@swa.org

Florida Phosphate Council
Susan Barfield
1435 East Piedmont Drive, Suite 211
Tallahassee, FL 32308
Ph: 850-224-8238
Fax: 850-224-8061
e-mail: susan@flaphos.org

LEE COUNTY

Landers Law Firm
Wright/LaVia
310 West College Avenue
Tallahassee, FL 32301
Ph: 850-681-0311
Fax: 850-224-5595
e-mail: swright@landersandparsons.com
jlavia@landersandparsons.com
Attorneys for Lee County

SUGARMILL WOODS CIVIC ASSOC.

Michael Twomey
Post Office Box 5256
Tallahassee, FL 32314-5256
Ph: 850-421-9530
Fax: 850-421-8543
e-mail: miketwomey@talstar.com
Attorney for Sugarmill Woods Civic Assoc.

By: Kenneth A. Hoffman
Kenneth A. Hoffman, Esq.

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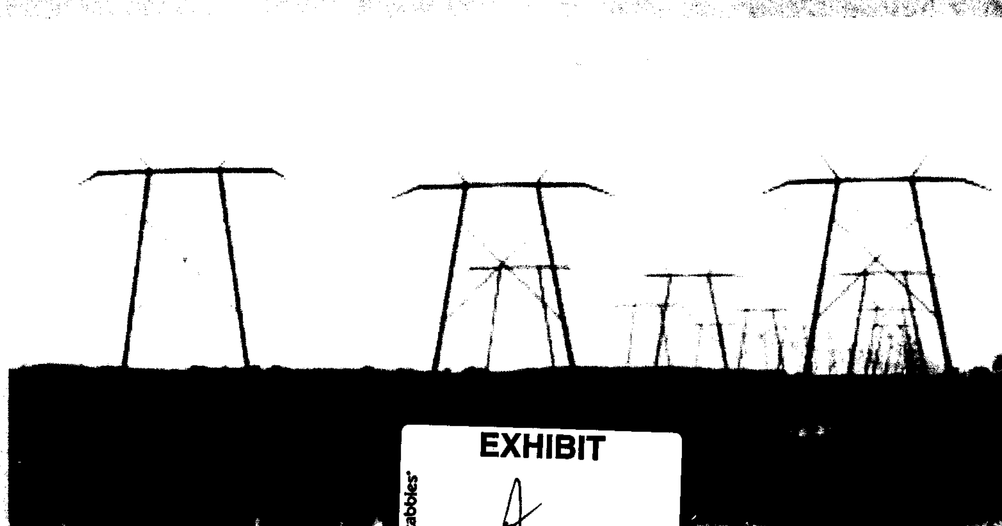
Cost-Benefit Study of the Proposed GridFlorida RTO

ICF CONSULTING

GRIDFLORIDA



EXHIBIT

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LIST OF EXHIBITS

STUDY AUTHORS

Kojo Ofori-Atta
Judah Rose
Chris McCarthy
Himali Parmar
Ken Collison

Elliot Roseman
Shanthi Muthiah
Maria Scheller

EXECUTIVE SUMMARY

Introduction

This study examined the costs and benefits to Peninsular Florida consumers of transforming the current decentralized market to a centrally organized market under two modes of operation – a Day-1 only RTO and a Delayed Day-2 RTO. A Day-1 Only RTO configuration reflects 13 years of decentralized company operation, but with a single transmission provider under a single GridFlorida-wide transmission tariff. Thus, under a Day-1 RTO configuration, currently "pancaked" transmission charges are eliminated. A Delayed Day-2 RTO configuration comprises three initial years of Day-1 operation, followed by 10 years of Day-2 operation. Under Day-2 operation, unit commitment and dispatch for the entire Peninsular Florida region is centralized under the GridFlorida RTO, with all market participants taking transmission service from the RTO under a single tariff. Each of these two RTO modes of operation is compared to a Base Case that reflects the current decentralized market, with individual company and control area operation, multiple transmission providers and "pancaked" transmission rates.

Cases Examined

As part of this assessment, ICF reviewed and analyzed a Reference Set of Cases (Base Case, Day-1 Case and Delayed Day-2 Case) and two sensitivity analysis cases – JEA and TALL as non participants of Grid Florida, and a Market Imperfection Case which addresses real world imperfections with unit commitment compared to the model outcome. Each case spans a 13-year forecast period, representing the period from 2004 through 2016. Exhibit ES-1 provides a summary of all the cases modeled.

Exhibit ES-1
Summary of Cases Analyzed

	Base Case	Day-1 Case	Delayed Day-2 Case	Total Number of Cases
Reference Cases	Yes	Yes	Yes	**3**
Sensitivity Analysis – JEA and TALL Out Case	Unchanged from Reference Case	Not in Scope of Study	Yes	**1**
Sensitivity Analysis – Market Imperfection Case	Unchanged from Reference Case	Not in Scope of Study	Yes	**1**
Total Number of Cases	**1**	**1**	**3**	**5**

Summary of Quantitative RTO Costs and Benefits

Exhibit ES-2 summarizes the quantitative RTO costs and benefits across all the cases examined.

Exhibit ES-2
Summary of Quantitative RTO Costs and Benefits (Million 2004$)
NPV (Years 1-13)[1]

Case	RTO Operation	RTO Benefits[1]	RTO Costs[2]	Net Quantitative Benefit/Costs[3]
Reference Cases	Day-1 Only	71	775	-704
	Delayed Day-2	968	1,253	-285
JEA and TALL Out Case	Delayed Day-2	891		-362
Market Imperfection Case	Delayed Day-2	810		-443

[1,2]All costs and benefits are discounted using a 3.15% real discount rate over the 13-year forecast period.
[3]The RTO Costs presented are estimates associated only with the new RTO. None of the potential changes in existing utility operational costs has been considered in this estimate.

A comparison of the quantitative RTO costs and benefits in net present value terms over the 13-year forecast period indicates a loss in all the cases examined, before considering qualitative costs/benefits and other utility operational cost changes. Whereas the quantifiable benefits under Delayed Day-2 RTO operation were

[1] All costs and benefits were discounted using a 3.15 percent real discount rate

substantial, and ranged from approximately $810 million in the Market Imperfection Case to almost $968 million in the Reference Case, the cost of a "greenfield" Delayed Day-2 RTO with wholly new systems, physical facilities and personnel, designed along FERC's Standard Market Design principles, is also very significant at $1.25 billion. The quantitative benefits to Peninsular Florida consumers of Day-1 Only RTO operation is $71 million over this period, while the quantitative start-up and operating costs of a "greenfield" Day-1 RTO is $775 million. Thus, the Day-1 RTO configuration reflects an estimated net loss of $704 million.

The quantitative analysis of the Day-1 RTO and Delayed Day-2 RTO indicate that the majority of the benefits to Peninsular Florida consumers come from centralized market operation, especially from centralized unit commitment[2]. The model calibration exercise revealed through the realized hurdle rates that the inefficiencies associated with unit commitment are by far larger than those associated with dispatch. This outcome is not surprising because in Peninsular Florida, more than ten entities separately commit units to meet load for a system with a total peak load of approximately 43 GW[3]. In systems such as PJM (116 GW); NYISO (31 GW) and ISO-NE (25 GW), a single entity performs unit commitment. Secondary benefits arise from centralized dispatch, which is related to real time operation of the generating units, but the inefficiencies associated with dispatch are not nearly as large as those associated with unit commitment, as there is already a high level of connectivity between control areas in Florida and most transactions occur between adjacent systems. For these reasons, maintaining a

[2] Centralized commitment is the day-ahead determination of which generating units will be used to meet load the following day.

[3] The three jurisdictional utilities comprise almost 77% of the load and the incremental benefit of centralized unit commitment may not be as large as the incremental benefit of unit commitment for the eight non-jurisdictional utilities that perform centralized unit commitment.

decentralized unit commitment and dispatch operation under a Day-1 RTO configuration, similar to the existing market, is expected to yield only moderate benefits.

Qualitative Factors: There are also various qualitative factors that should be considered along with the quantitative costs and benefits estimated for the Day-1 and Delayed Day-2 RTO operations. These qualitative costs and benefits are summarized in Exhibit ES-3.

Exhibit ES-3
Potential Impact of Qualitative Factors in Day-1 and Day-2 RTOs

Qualitative Factor	Potential Day-1 Impact		Potential Day-2 Impact	
	Costs	Benefits	Costs	Benefits
Investment Efficiency				
Transmission		√		√
Generation		√		√
Bilateral Long-Term Contracting		√		√
Elimination of Contract Path Scheduling		√		√
Transition Risks	√		√	
Market Transparency		√		√
Scope, Organizational and Regulatory Issues	√		√	
Other factors				
ROE		-		-
Inter-Regional Tariffs		√		√
Efficiency and Standards		√		√
Merchant Power Plants		√		√

Jurisdictional and Non-Jurisdiction RTO Costs/Benefits and Transmission Owner Cost Shifts

The quantitative RTO costs and benefits in the Reference Case were disaggregated between jurisdictional utility consumers and those that are non-jurisdictional to the FPSC. The benefits to each of these two groups were estimated from the change in their local generation and bilateral transactions (between the two groups) and external imports in response to the change in market structure in Day-1 and Day-2. The quantitative RTO costs were also disaggregated between the two groups based on load ratio share i.e., 77% for the jurisdictional consumers and 23% for the non-jurisdictional consumers.

These jurisdictional and non-jurisdictional costs and benefits were combined with Transmission Owner cost shifts. Under the GridFlorida tariff, there are three factors which lead to cost shifts between transmission owners: (1) the costs of transmission dependent utilities (TDU) transmission facilities being included in transmission rates for all transmission customers, not just TDU customers; (2) the transmission facilities of all Peninsular Florida utilities being blended together in a single region-wide rate; and (3) multiple access charges being eliminated for service within GridFlorida ("de-pancaking"). The net impact of the cost shifts is that the jurisdictional transmission owners' cost to serve retail customers increases, thus increasing their retail rates, and the non-jurisdictional transmission owners' cost and retail rates decreases.

Exhibit ES-4 shows the combined effect of the transmission owner cost shifts and jurisdictional and non-jurisdictional costs and benefits.

Exhibit ES-4
Summary of Jurisdictional and Non-jurisdictional Consumer Day-1 and Delayed Day-2 RTO Costs and Benefits (2004 Million$)

NPV (Years 1-13)	Day-1 Only Operation			Delayed Day-2 Operation		
	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit
RTO Benefits	-11	82	71	411	557	968
RTO Costs	599	176	775	969	284	1,253
Transmission Owner Costs[4] (Cost Shifts)	525	-525	-	525	-525	-
Net Benefits	-1,135	431	-704	-1,083	798	-285

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate.

[4] The Transmission Owner costs shifts have been estimated based on the GridFlorida tariff filed with the FPSC by the GridFlorida Applicants. However the quantitative RTO benefits have been estimated using a simplified form of the tariff structure because the tariff as filed did not lend itself to analytic modeling. Thus, the net benefits shown in Exhibit ES-4 should be interpreted as indicative rather than definitive.

Overall, under Day-1 RTO Operation, jurisdictional consumers incur a loss of approximately $1.1 billion and non-jurisdictional consumers earn a benefit of approximately $431 million. Under Delayed Day-2 RTO operation, jurisdictional consumers incur a loss of approximately $1.1 billion and non-jurisdictional consumers earn a benefit of approximately $798 million.

Conclusions

The overall outcome of net benefits or costs to Peninsular Florida consumers depends on both quantitative and qualitative aspects of the RTO. ICF's analysis shows that the prospects of a Day-1 RTO are bleak, especially if designed along a "greenfield" RTO with wholly new systems, personnel and physical facilities because while the fixed costs are high, the benefits of a Day-1 RTO operation are not as large as a Delayed Day-2 RTO operation. The quantitative Delayed Day-2 RTO benefits to Peninsular Florida consumers come largely from centralized market operation, especially from unit commitment. Secondary benefits come from centralized dispatch, but the inefficiencies associated with dispatch are not nearly as large as those associated with unit commitment, as there is already a high level of connectivity between control areas in Florida and most transactions occur between adjacent systems. The GridFlorida Delayed Day-2 RTO could breakeven under the scenarios examined in this study if the net benefits from the qualitative factors and the change in utility operational costs should be within the range of $285 million and $443 million over the 13-year forecast period. This study also indicates that the non-jurisdictional consumers would receive net positive benefits of $798 million from the implementation of a GridFlorida Delayed Day-2 RTO while jurisdictional consumers would receive a net loss of $1.1 billion.

While the overall GridFlorida consumer cost/benefit remains unchanged, the RTO costs allocation and the transmission owner cost shifts exacerbates the quantitative loss to jurisdictional consumers and improves the benefits to non-jurisdictional consumers.

CHAPTER ONE
PROJECT BACKGROUND

1.1 Background on the FPSC Order

In September 2003, the Federal Energy Regulatory Commission (FERC) met with the Florida Public Services Commission (FPSC) and discussed the principles surrounding the creation of a regional transmission organization (RTO) in Florida. As a follow up to this meeting, on December 15, 2003, the FPSC issued Order PSC-03-1414-PCO-EI establishing revised dates for Stakeholder workshops on the potential structure and impacts of creating an RTO in Peninsular Florida (GridFlorida).

The FPSC's issues list for the Pricing and the Market Design Workshops included an issue for the continued review of RTO costs and benefits. The applicants engaged ICF to evaluate the costs and benefits of GridFlorida. ICF worked with the stakeholders to model GridFlorida consistent with the Applicant's September 19, 2002 filing "Petition of the GridFlorida Companies Regarding Prudence of GridFlorida Market Design". In addition, to the extent that an RTO structure based on the principles stated in the filing differed from an RTO structure based on FERC's guidelines per the Standard Market Design (SMD) and subsequent White Paper dated April 2003, these differences were analyzed.

1.2 Study Overview and Objectives

To comply with the requested review of RTO costs and benefits, ICF Resources LLC ("ICF") was engaged by GridFlorida LLC ("GridFlorida") to independently assess the costs and benefits to Peninsular Florida consumers of restructuring the Peninsular Florida power market from the existing decentralized utility control area operation, and bilateral market to a centrally organized one, i.e., the GridFlorida RTO. This document presents the results of ICF's assessment.

In both Peninsular Florida and in general, the primary costs and benefits from centrally coordinated and dispatched markets through an RTO derive from four principal sources, which include:

- Operational efficiency;
- Investment efficiency;
- Market participant net costs or benefits from working with the new RTO; and
- Cost of forming and maintaining a new RTO.

Of the various costs and benefits associated with market restructuring, some can be readily quantified, while others are best left to qualitative assessment. The costs and benefits that are quantifiable lend themselves to commercially available analytic modeling tools based on approaches widely accepted by the industry. ICF deployed a range of analytical tools, as described in Chapter 3, to develop these quantitative assessments. ICF also identified and discussed a number of qualitative factors and the potential for each of these factors to provide benefits or costs. These are described in Chapter 5.

In this study, most of the operational efficiencies were quantified using industry accepted analytical techniques, while the investment efficiency and selected aspects of operational efficiencies have been qualitatively assessed. Arguably, some of the qualitative costs and benefits may be quantifiable, and several approaches have been suggested for doing so. However, we note that the industry as a whole has not accepted any one approach so in this study, we believe these factors are best left as qualitative features of the report. In addition, analyzing individual market participants' costs or benefits from working with the RTO were not part of the scope of this study. All quantified costs and benefits have been compared to a continuation of the status quo (i.e. a "Base Case" reflective of today's decentralized wholesale power market) over a thirteen year forecast period.

A key component of the ICF study involved the identification of the significant structural and functional differences between the Peninsular Florida market today and a future centrally organized market. These differences enable us to anticipate the quantifiable costs and benefits that would be derived from the implementation of a GridFlorida RTO. For example, the elimination of "pancaked"[5] transmission rates between existing control areas should improve the efficiency in generation dispatched to serve load and meet reserve requirements. Thus, to the extent there are no internal transmission constraints, the least cost generation facilities serving the Peninsular Florida market as a whole will be dispatched, which should result in overall benefits to consumers. Depending on their magnitude, pancaked transmission tariffs can act like trade obstacles that effectively segment a market into sub-markets. Similarly, decentralized unit commitment and dispatch operations act like trade obstacles. When such barriers

[5] "Pancaking" is a term commonly used to explain the practice of incurring multiple wheeling charges when moving power from one area to another across multiple utility territories, each with its own transmission system costs and associated wheeling charge.

exist, each sub-market realizes a local optimum instead of a Peninsular Florida-wide optimum, as would be the case in a centrally organized RTO market[6].

As part of the overall cost-benefit assessment, it is also critical to assess the costs of forming and maintaining a new organization in the form of the GridFlorida RTO that would provide various functions necessary for the centralized market operation. This evaluation involved a detailed bottom-up assessment of the costs likely to be associated with each key function and department of the RTO, an assessment which benefited from extensive research on the experience of other RTOs.

In this study, ICF evaluated two specific RTO configuration alternatives, namely a "Day-1" only operation and a "Delayed Day-2" operation. These alternative configurations differ in their structural and operational functions. A Day-1 only RTO maintains the existing decentralized company operation but transmission service is provided by the GridFlorida RTO and under a single GridFlorida-wide transmission tariff[7]. Thus in Day-1 we eliminate currently "pancaked" transmission charges and all transmission customers take transmission service from the RTO. A Delayed Day-2 operation reflects three initial years of Day-1 operation followed by ten years of Day-2 operation. Under Day-2 operation, the entire market is centralized under the GridFlorida RTO. Unit commitment and dispatch is centralized to meet the GridFlorida-wide load and reserve requirements.

1.3 Stakeholder Participation

This study was driven by a multi-faceted and interactive Stakeholder process designed to ensure the accurate representation of the Peninsular Florida system and to benefit

[6] Theoretically, a centralized market should provide a Peninsular Florida-wide optimum.

[7] Although the GridFlorida Applicants filed a GridFlorida tariff that phases out "pancaking" of transmission rates over time, in this study a single rate has been used as a simplification.

from the feedback of all Stakeholders. The scope of the study was developed and approved by the GridFlorida Applicants in consultation with the FPSC and other Stakeholders, including municipal utilities, cooperative utilities, and independent power producers active in the Peninsular Florida market. A Project Steering Committee comprising the GridFlorida Applicants provided guidance and administration in gathering Stakeholder and relevant market data, and in providing ICF with the year-by-year representation of the transmission system over the 13 year forecast period. For example, all generation resource thermal and cost data used for modeling was provided confidentially by the individual Stakeholders in the best position to supply that data. In addition to regular conference calls with various participants during the course of the study, ICF conducted six Cost-Benefit Working Group (CBWG) meetings with the entire Stakeholder Group to:

- Discuss the study approach and assumptions;
- Review interim modeling results;
- Solicit Stakeholder comments; and
- Present results incorporating Stakeholder feedback.

Additionally, ICF established three time periods to afford Stakeholders with an opportunity to provide written comments on the Study Approach, the preliminary RTO cost estimates and the preliminary RTO benefit estimates. Relevant feedback from Stakeholders was incorporated into the study.

Thus, in sum, this study, performed with significant Stakeholder participation, provides a comprehensive evaluation of the costs and benefits of forming a GridFlorida RTO, many of which were quantifiable, and some of which were not.

The remainder of this report is organized into six Chapters and Appendices. Chapter 2 discusses the Peninsular Florida power market and the proposed GridFlorida market structure. Chapter 3 discusses the analytic approach to quantifying costs and benefits. Chapter 4 presents the quantitative results, and Chapter 5 discusses qualitative factors. The quantitative RTO costs and benefits are disaggregated between jurisdictional and non-jurisdictional consumers in Chapter 6 including discussion of transmission owner costs shifts that result from blending all transmission facilities under a single GridFlorida tariff. We finally present our conclusions in Chapter 7, followed by relevant Appendices.

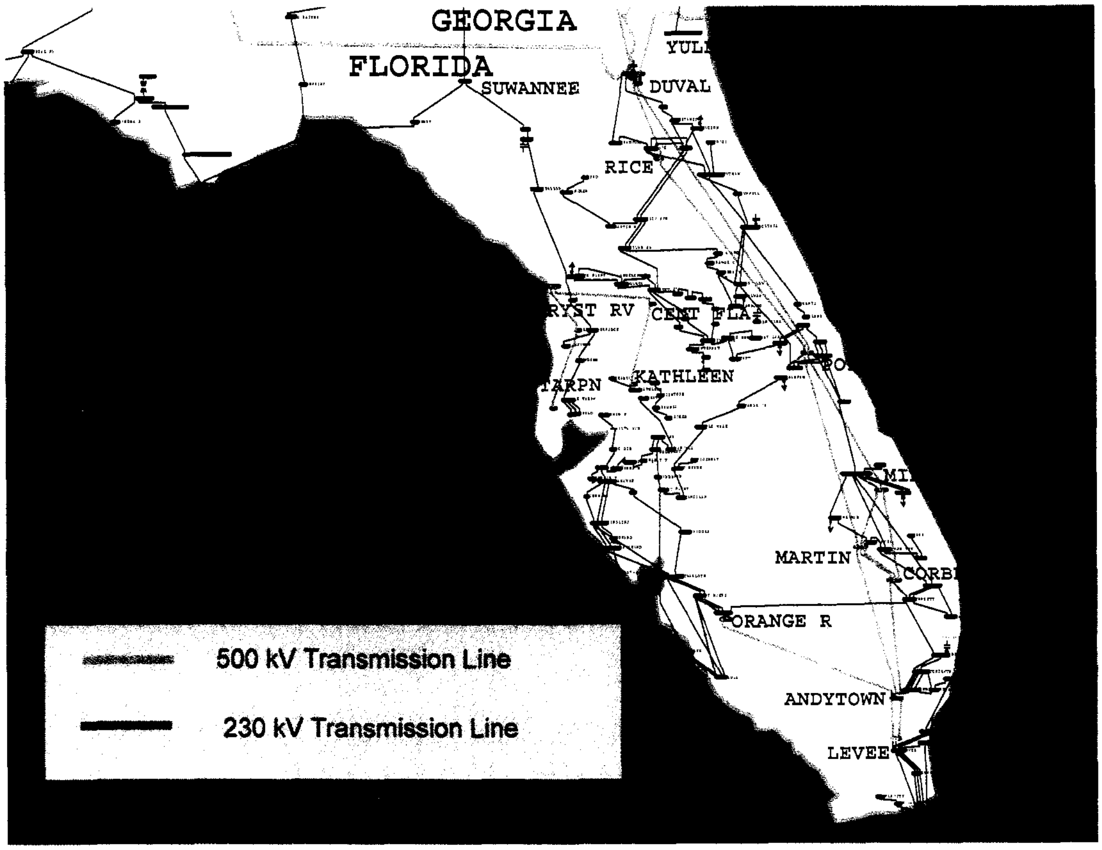
CHAPTER TWO
THE PENINSULAR FLORIDA POWER MARKET AND THE PROPOSED GRIDFLORIDA MARKET STRUCTURE

This chapter provides background on the Florida power market, including an introduction to the Florida Reliability Coordinating Council (FRCC) and the geographic extent of its market coverage, an overview of the physical transmission condition (external and internal), and the supply/demand fundamentals prevailing in the market. This chapter also provides an overview of the current market structure and participants and concludes with a discussion of the proposed market structure.

2.1 Background on the FRCC

Peninsular Florida was formerly a sub-region of the Southeastern Electric Reliability Council (SERC). However, in 1996, the FRCC was established after the Florida Electric Power Coordinating Group (FCG) decided to establish its own reliability council to ensure and enhance the future reliability and adequacy of bulk electricity supply in Florida, in recognition of Florida's unique reliability needs. The FRCC includes all utility systems within the state's border, with the exception of the northwestern Panhandle, which is partially operated by Gulf Power Company and remains part of SERC.

Exhibit 2-1
Peninsular Florida Transmission System



In December 2001, the FRCC amended its Bylaws to provide for a balanced sector board and representation on its standing committees. The FRCC's activities are directed by its Board of Directors, which is comprised of top-level executives from members of FRCC. Technical activities are carried out by the Engineering and Operating Committees. The Market Interface Committee addresses the effects of new and evolving market practices on electric system reliability, and ensures that the impacts of the electric industry's reliability standards are addressed from the market perspective. Thus, there already exists in Florida an organization designed to coordinate reliability[8] that the proposed GridFlorida RTO would interact with.

2.2 Florida's Interconnectivity with the Rest of the Grid

Peninsular Florida operated its electric system in virtual isolation from the rest of the Southeast until the summer of 1982, when two 500 kV interconnections with Georgia Power were established. Even now, it is relatively isolated in terms of its electric power interconnections. Its only link with another system is with SERC at the Florida/Georgia border and in the Florida Panhandle. This makes FRCC among the regions in the US with the lowest potential to import or export power. Based on North-America Electric Reliability Council (NERC) and FRCC forecasts of import capability and demand, only about 9 percent of FRCC's net internal peak demand can currently be met through imports. Only the ERCOT region in Texas is more electrically isolated among the regions typically analyzed in the continental United States (US).

The interconnections between Florida and the Southern region within SERC consist of:

- 500 kV transmission lines from Duval to Hatch and from Duval to Thalman;
- 230 kV transmission lines from Port St. Joe to Callaway, from Sub 20 to S. Bainbridge, from Suwannee to Sterling, and from Yulee to Kingsland;
- 115 kV transmission lines from Jasper to Tarver, from Jasper to Wrights Chapel, from Suwannee to Twin Lakes and from Woodruff to Scholz.

[8] The FRCC has contracted with FPL to provide Security Coordination services for the Peninsular Florida power system.

As mentioned earlier, the state's unique geographic location and relatively modest inter-regional transfer capability were the main forces behind the establishment of the FCG in 1972, and the subsequent Florida Reliability Coordinating Council in 1996.

2.3 Transmission Within Florida

In contrast to external interconnectivity, there is significant and substantial interconnectivity within Florida. The utilities within Peninsular Florida are interconnected via a high-voltage system made up of 500 kV and 230 kV lines. Double circuit 500 kV lines run the length of the State's eastern seaboard and enable significant power flows from the north to load centers in the southeast and around Miami. Florida's transmission system is considered by NERC to be adequate for power transactions within the region, with no problems that would significantly affect reliability. Indeed, only one transmission loading relief (TLR) event which was due to a hurricane has occurred in the FRCC since 2000.

2.4 Supply and Demand Conditions

FRCC is an average sized market compared to other power markets in the U.S. Net internal peak demand is approximately 43 GW[9], and Florida has a bimodal winter and summer peaking profile. Whether looking at 10 year rolling averages or more recent averages, peak demand and energy growth rates in Florida has been very strong (energy demand has been in excess of 3.0 percent on average), making Florida one of the fastest growing markets in the US. This is in comparison to the US average growth rate of closer to 2.5 percent.

[9] 2004 actual peak demand was approximately 43 GW

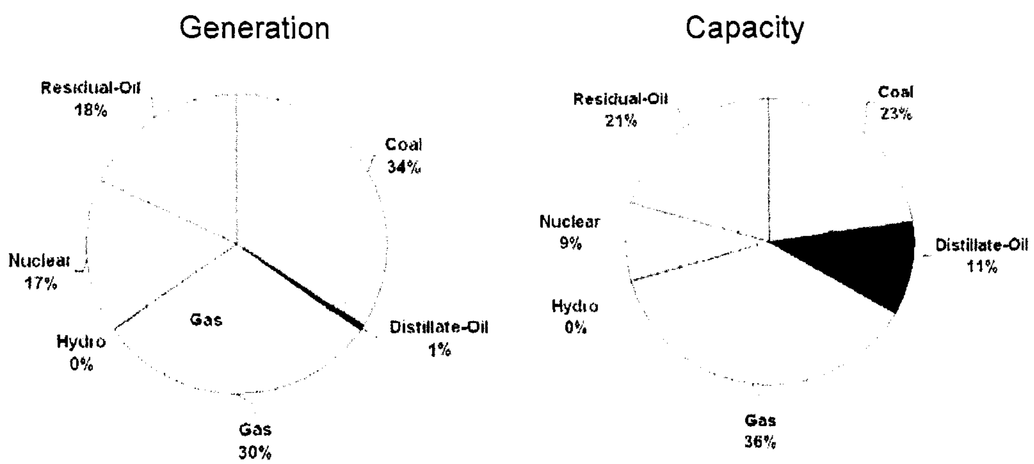
Exhibit 2-2
Historical Peak Demand and Energy Growth Rates – FRCC

Year	Peak Demand (MW)	Energy (GWh)
2003	40,475	219,021
2002	40,696	211,116
2001	39,062	200,134
2000	37,194	196,561
1999	37,493	188,598
1998	38,730	188,384
1997	35,375	175,557
1996	35,444	173,377
1995	34,524	169,021
1994	32,904	159,861
1993	32,823	153,468
1992	30,601	147,464
1991	28,818	146,906
1990	27,266	142,502
1989	27,972	142,959
Historical Annual Average Growth Rates (%)		
10 Year Rolling Averages		
1993-2003	2.12%	3.62%
1992-2002	2.89%	3.65%
1991-2001	3.09%	3.14%
1990-2000	3.15%	3.27%
1989-1999	2.97%	2.81%
Average of 10 Year Rolling Averages (1989-2003)	**2.84%**	**3.30%**

Source: NERC ES&D 2004

The Florida capacity mix is diverse (see Exhibit 2-3). More oil is used in generating power in Florida than in any other state, with oil/gas steam units accounting for almost 20 percent of FRCC's capacity. Due to natural gas pipeline constraints, a relatively large portion of Florida's combustion turbines can also be oil fired, specifically distillate-fired. Florida made efforts after the oil crises of the 1970s to increase its use of fuels other than oil, resulting in significant coal use even though there is no coal mined in the state and it is relatively costly to transport coal to Florida. Nuclear and combined cycle units make up the remainder of Florida's capacity mix.

Exhibit 2-3
Capacity and Generation Mix in FRCC – 2003



Source: GridFlorida Applicants and Stakeholder
The total reported capacity and generation is the sum of the 2003 unit capacity and dispatch reported by Florida Power & Light, Progress Energy Florida, Tampa Electric Company, Seminole Electric Cooperative and member systems, Gainesville Regional Utilities, Jacksonville Electric Authority, Florida Municipal Power Agency (FMPA) member systems, Orlando Utilities Commission, Lakeland Electric, City of Tallahassee Electric Department. Excludes resources of New Smyrna Beach, Reedy Creek Improvement District and City of Homestead.

Florida's capacity mix has been changing over the last several years with over 15 GW of newly operational capacity having come on-line between 2001 and 2005 (see Exhibits 2-4 and 2-5). Capacity additions in Florida in the 1999 to 2001 timeframe lagged those of the neighboring markets of Southern Company and Entergy. However, there was significant capacity expansion activity in Florida thereafter. The majority of builds consisted of efficient combined cycle units due to the arbitrage opportunities against higher heat rate oil/gas steam units.

Exhibit 2-4
FRCC Summary of Recent and Under Construction Capacity

	2001	2002	2003	2004	2005	2006
Combined Cycle	141	3,362	2,960	1,642	2,628	0
Combustion Turbine	1,391	2,622	0	0	99	537
Total	**1,532**	**5,984**	**2,960**	**642**	**2,727**	**537**

Source: GridFlorida Applicant and Stakeholder Data

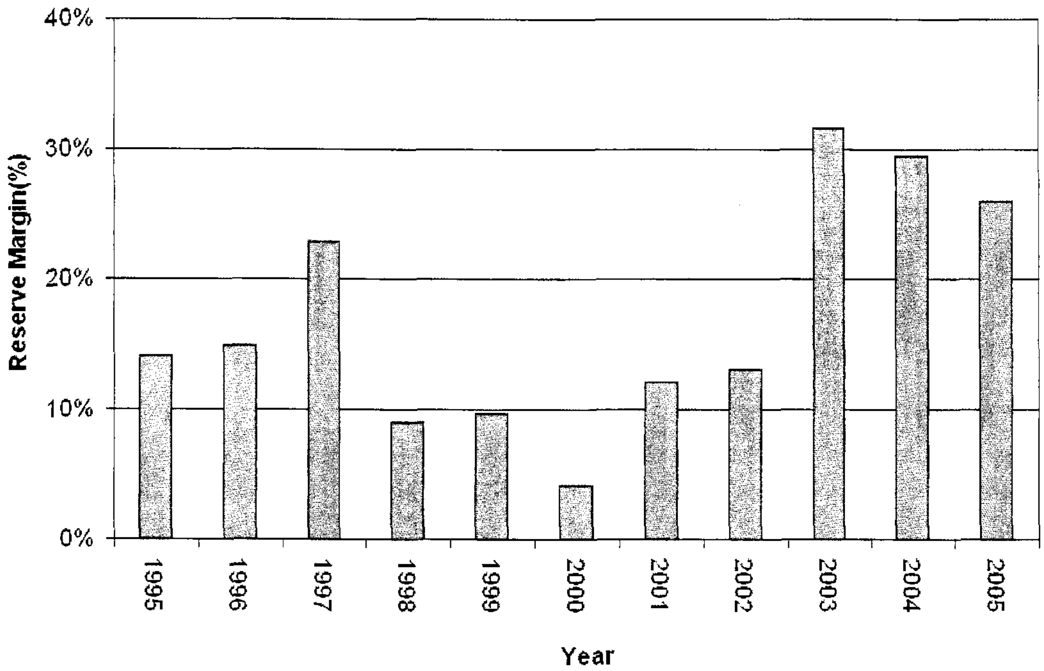
Exhibit 2-5
FRCC Capacity Mix 2001 to 2005

Year	2001	2002	2003	2004	2005
Combined Cycle	4,165	7,527	10,487	12,129	14,757
Cogens	821	821	821	821	821
Combustion Turbine	8,420	10,867	10,867	10,867	10,966
Hydro	47	47	47	47	47
Nuclear	3,928	3,928	3,928	3,928	3,928
Steam	10,578	10,753	10,753	10,753	10,753
Coal	9,470	9,470	9,470	9,470	9,470
Other	399	399	399	399	399
Grand Total	**37,829**	**43,813**	**46,773**	**48,415**	**51,142**

Source: GridFlorida Applicant and Stakeholder Data

Increases in demand and limited plant construction contributed to lower reserve margins in the late nineties. Since that time, a development boom has pushed reserve margins above their equilibrium levels (see Exhibit 2-6). The reserve margin in FRCC in 2005 under normal conditions is estimated at approximately 21%. FRCC has typically maintained a 15% planning reserve margin in the region. This target reserve margin level is within the typical range of US reserve margin levels (15-18 percent). However, the jurisdictional utilities have an arrangement with the FPSC to maintain a 20% reserve margin level. At this target level, with additional builds forthcoming and a rapid demand growth rate, Florida is expected to maintain equilibrium supply/demand balance conditions well ahead of most other parts of the Eastern Interconnect.

Exhibit 2-6
Reserve Margins in FRCC: 1995 – 2005



Source: FRCC State Resource Plan 2005
Note: Reserve Margin calculated as Total Installed Capacity/Actual Peak Demand and does not include Exports and Imports. FRCC total installed capacity includes non-utility capacity and merchant capacity

2.5 Current Florida Market Structure

The major investor-owned utilities (IOUs) in Florida include Florida Power & Light (FPL), Tampa Electric Company (TECO) and Progress Energy Florida (PEF). These three IOUs together comprise over 70 percent of all electric power sales in the FRCC. In fact, FPL alone accounted for nearly half of all generation and sales in the region in 2003 (see Exhibit 2-7). In addition to the IOUs, Florida also has a strong public power sector. The larger municipal and cooperative systems include Jacksonville Electric Authority, Florida Municipal Power Agency (FMPA) member systems, Seminole Electric Cooperative (SECI) member systems, Kissimmee Utility Authority, Lakeland Dept. of Electric & Water Utilities, Orlando Utilities Commission (OUC), Gainesville Regional Utilities, City of Homestead, Reedy Creek Improvement District and City of Tallahassee Electric Department (TALL). Of these entities, four have direct ties with Southern Company (SOCO), namely the City of Tallahassee Electric Department, Jacksonville Electric Authority, Florida Power & Light and Progress Energy Florida.

Exhibit 2-7
FRCC 2003 Market Sales By Utility

Utility	Sale to End Users (MWh)	Share
Florida Power & Light	99,635,281	45.3%
Progress Energy Florida	37,956,700	17.3%
Tampa Electric Company	18,242,316	8.3%
Jacksonville	12,582,876	5.7%
Gulf Power Company	11,248,860	5.1%
Orlando Utilities	7,567,400	3.4%
Withlacoochee	3,210,356	1.5%
Lee County	3,116,182	1.4%
Clay	2,873,635	1.3%
Lakeland	2,736,686	1.2%
Tallahassee	2,601,510	1.2%
Sumter	2,099,972	1.0%
Gainesville	1,785,967	0.8%
Ocala	1,275,044	1%
Kissimmee	1,218,620	1%
Reedy Creek	1,124,269	1%
Others[10]	10,503,065	5%
TOTAL	219,778,737	100%

Source: Statistics of the Florida Electric Utility Industry 2003, FPSC

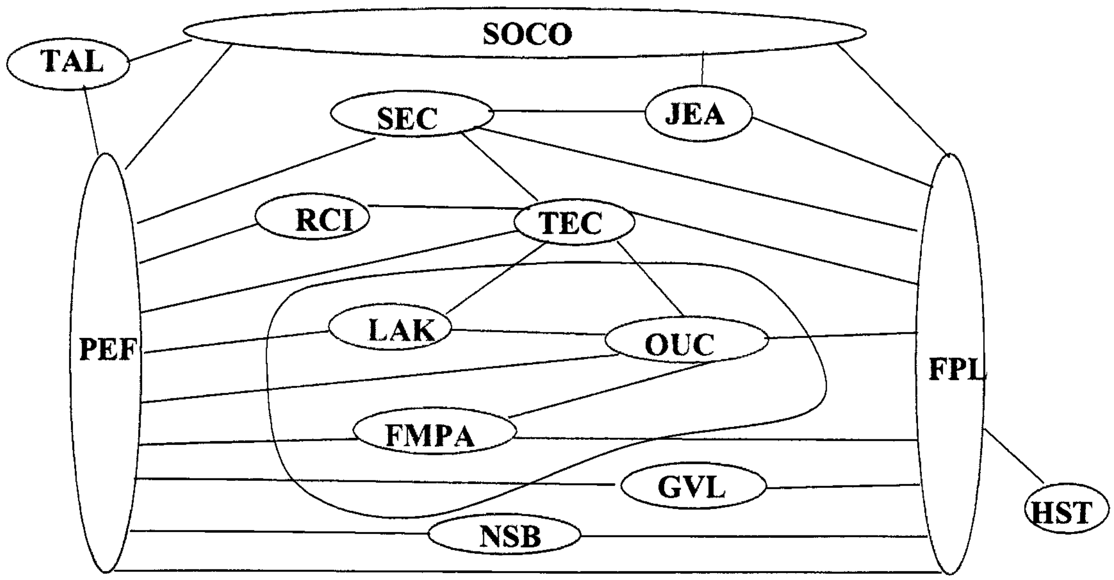
The Peninsular Florida power market functions through decentralized, utility control area operation. Exhibit 2-8 shows a schematic of the interconnected control areas. There are currently eleven entities responsible for transmission operations in Peninsular Florida. Each of these entities is responsible for scheduling and dispatching their

[10] Includes Choctawhatchee, Central Florida, Florida Keys, Jacksonville Beach, Key West, Leesburg, New Smyrna Beach, Talquin, Fort Pierce, Bartow, Vero Beach, Florida Public Utilities, and Peace River etc. Maximum and average sales to end users in this group are approximately .93 TWh and 0.32 TWh respectively.

generation resources to serve their load and reserve requirements. Simultaneously, these eleven transmission providers coordinate with each other during real time operations to balance generation against load and thereby maintain system frequency. FPL provides security coordination services for the entire FRCC region.

While Florida has never had a tightly operated pool, in 1976, Florida utilities began active power trading using a centralized power exchange called the Energy Broker Network (EBN). The EBN was a cost-based voluntary mechanism for marketing non-firm next hour electric energy among electric utilities that had sufficient generating capacity to meet their loads. While in operation, the EBN facilitated power marketing amongst the utilities by increasing transaction volumes and providing fuel cost savings to Florida consumers annually. The EBN was discontinued on September 1, 2000 because of rapid changes in the industry, such as the emergence of power marketing entities that sought alternative ways to market energy. Since then, utilities and marketers have engaged in bilateral trading, both within Florida and externally, capturing some cost savings. Trades are predominantly short-term, on a non-firm basis and recallable which introduces some amount of uncertainty in unit commitment decisions and may result in some market inefficiency. Some of the utilities have long-term, firm bilateral trade agreements.

Exhibit 2-8
Schematic Diagram of Interconnected Control Areas



PEF: Progress Energy Florida, FPL: Florida Power & Light Company, TEC: Tampa Electric Company, RCI: Reedy Creek Improvement District, SOCO: Southern Company, JEA: Jacksonville Electric, TAL: City of Tallahassee Electric Department, SEC: Seminole Electric Cooperative, LAK: Lakeland Electric, OUC: Orlando Utilities Company, FMPA: Florida Municipal Power Authority, NSB: New Smyrna Beach, GVL: Gainesville Regional Utilities, HST: City of Homestead

There are several other key features of the FRCC market structure and operation that this study took into consideration. For example:

- Some of the Florida utilities have resources external to FRCC which they regularly dispatch as network resources to serve their load in Florida. FPL and JEA for example jointly own the Scherer Unit 4 coal facility in Georgia and dynamically schedule this resource across their ownership share of the Southern Company/Florida transmission interface to serve their load. FPL, JEA and PEF also have Unit Power Sales (UPS) contracts which they treat similar to the Scherer unit.

- Utilities such as Seminole and FMPA have load embedded in other control areas and depend on transmission services of other entities to serve their load.

- Although Lakeland Dept. of Electric & Water Utilities (LAK), Orlando Utilities Commission (OUC), Florida Municipal Power Agency member systems (FMPA) are control areas, operationally they dispatch their facilities in a pool to meet their joint load and reserve requirements.

These and other features of the FRCC market, such as those described in the earlier section on supply/demand fundamentals, were captured in our assessment and modeling efforts.

2.6 Transmission Operations

Transaction scheduling in Peninsular Florida is performed by multiple transmission providers. Each transmission provider administers its own portion of Florida's Open Access Same-time Information System (OASIS) where Available Transfer Capability (ATC) and transmission rates for transmission services are posted. Each transmission provider, in coordination with the FRCC, calculates ATC on specific transmission corridors (Contract Paths) within its territory to reflect the throughput capacity of the network and sells ATC across these corridors to transmission customers. Transmission customers request transmission service from transmission providers along the path of the proposed transaction and the transmission providers approve and schedule the transaction, provided there is no reliability concern. However, the use of Contract Paths is not necessarily reflective of how power flows in a transmission network. Rather, it is an approach accepted within the industry to represent the commercial throughput capacity of the transmission network and to provide excess transmission capacity to prospective transmission customers. It is noteworthy that the use of Contract Paths for transaction scheduling is significantly different from how power is scheduled in Day-2 RTOs. Day-2 RTOs provide transmission access to those who value it the most. In the case without congestion, and ignoring losses, the least bid generation resource gets transmission access. When congestion occurs, a market based congestion management system provides the necessary re-dispatch, out of merit order, to give generation transmission access. Market participants that value transmission access can use Financial Transmission Rights (FTRs) to hedge against the congestion charges that result from re-dispatch. By contrast, under Contract Path, the transmission customer must prearrange transmission access across designated transmission corridors on a first-come, first-served basis. Each control area commits its resources to meet its next day load forecast, reserve requirements and sales commitments.

2.7 Proposed GridFlorida Market Structure

The proposed GridFlorida market structure is a Location-based Marginal Pricing (LMP), Financial Transmission Right (FTR), multi-settlement market model. LMP is a pricing scheme that is used for transactions in wholesale power markets. Under an LMP scheme, power prices vary by location due to transmission congestion and losses. Transmission congestion imposes costs on power consumers, as consumers at the receiving-end of a congested transmission line incur the cost of that congestion implicitly in their LMP. The cost associated with congestion can be hedged using FTRs, which are financial instruments that the holder may use to recover their congestion payments. The total number of available FTRs reflects the operating capacity of the grid - they are initially made available to market participants with entitlements to use the transmission system and they are subsequently traded in secondary markets.

The proposed GridFlorida RTO is designed to have two market settlements – a Day-Ahead market settlement and a Real-Time market settlement. The Day-Ahead market would provide participants with the opportunity to enter financially binding contracts to provide or consume power and also to allow them to avoid the potential volatility of the Real-Time markets. Day-Ahead market transactions are settled at Day-Ahead prices and Real-Time market transactions are settled at Real-Time prices.

The structure of the proposed GridFlorida RTO consists of one main control area (the RTO) and a number of Control Zones comprised of the existing Utility Control Areas. The functional responsibilities of the Control Zones are expected to change gradually as the RTO and the Peninsular Florida market evolves from inception through Day-1 and subsequently, Day-2 operation. Throughout the RTO developmental process, the Control Zones would work in tandem with the RTO, but would not be part of the RTO organization. The Control Zones would continue to be part of their parent utility organizations, a structure similar to the current MISO[11] framework and consistent with the September 2002 FPSC filing of the GridFlorida Applicants. In this filing, the GridFlorida Applicants proposed a hierarchical control area structure which retains the existing Utility Control Areas operating under a main GridFlorida RTO.

[11] Midwest Independent System Operator

The table below summarizes the functions of the proposed GridFlorida RTO under Day-1 and Day-2 operation. The roles and responsibilities of the Control Zones and the main RTO in this study were designed to ensure compliance with FERC Order 2000. For example, the responsibilities for the GridFlorida RTO under Day-1 operation would include OASIS administration, ATC and Total Transfer Capability (TTC) determination, Open Access Transmission Tariff (OATT) Administration, Security Coordination, Transmission Planning, System Operations and Market Monitoring. The Control Zones would balance generation with load in their respective geographic regions, and each Control Zone would be responsible for unit commitment and economic dispatch of generation to serve their load. The proposed GridFlorida RTO would use non-market mechanisms such as Transmission Loading Relief (TLR) calls and generation re-dispatch to manage transmission congestion in Day-1. The Control Zones would self-provide their ancillary services needs and administer operating reserves according to the existing FRCC Reserve Sharing Agreement. The Control Zones would maintain primary responsibility for ensuring Resource Adequacy. Day-1 market monitoring functions are designed to be minimal and for the purposes of this work, would be outsourced. The RTO would perform minimal commercial functions in Day-1, including credit checks for transmission customers and billing and settlement functions for transmission access.

Exhibit 2-9
GridFlorida Responsibilities Under Day-1 and Day-2 operation

GridFlorida Responsibilities	Day-1	Day-2
OASIS Administration	YES	YES
Tariff Administration	YES	YES
Security Coordination	YES	YES
Transmission Planning	YES	YES
System Operations	YES	YES
Congestion Management	Redispatch	LMP
Resource Adequacy	N/A	YES
FTR Market Management	N/A	YES
Day Ahead and Real-time Market Administration	N/A	YES
Market Monitor	Minimum	YES

Under Day-2 operation, the proposed GridFlorida RTO would expand its Day-1 responsibilities to include operation of Day-Ahead and Real-Time markets, and market-based congestion management using transmission rights. The RTO would ensure resource adequacy and would be responsible for billing and settlement of all non-bilateral RTO transactions. Because of the introduction of a Day-Ahead market, a Real-Time market and an FTR market, the market monitoring responsibilities for Day-2 would increase significantly.

The GridFlorida RTO would manage the single GridFlorida-wide transmission tariff under both Day-1 and Day-2 operations. The applicable transmission rate was filed by the GridFlorida Applicants at the FPSC Pricing Issues workshop on March 17-18, 2004. In their filing the GridFlorida Applicants stated that:

> "GridFlorida's rates must be designed to recover the transmission revenue requirements of all Transmission Owners (TOs) and the revenue requirements associated with GridFlorida's grid management charge. The grid management charge for GridFlorida shall include the annual operating costs for GridFlorida and a five-year amortization of the recovery of the start-up costs of GridFlorida. Consistent with GridFlorida's current pricing protocol, GridFlorida's rate design shall consist of (a) zonal rates, (b) system-wide rates and (c) a phase out of zonal rates in the sixth through tenth year. The FPSC shall have the opportunity to review and provide a final approval of the phase out of zonal rates prior to the end of the 5th year of commercial operations of GridFlorida."

Under both Day-1 and Day-2 operation, all market participants will take transmission service from the GridFlorida RTO under its tariff[12].

As described in this chapter, while the physical fundamentals may remain largely unchanged in the near-term, the existing Peninsular Florida market and the proposed GridFlorida RTO have significant structural and operational differences, especially in key operational areas such as unit commitment and dispatch, transmission scheduling, and applicable transmission rates. When the impact of these differences is appropriately modeled for a future time period, they provide results that can be used to support policy decisions on the formation of an RTO in Peninsular Florida.

[12] This study did not model the full detail of the proposed GridFlorida tariff filed by the GridFlorida Applicants. The exact tariff structure did not lend itself to analytic modeling. Therefore, a simplified form of the tariff was modeled under Day-1 and Day-2 RTO operation.

CHAPTER THREE
ANALYTIC APPROACH AND CASES EXAMINED

3.1 Introduction

As mentioned earlier, of the various costs and benefits associated with market restructuring, some can be readily quantified, while others are best left to qualitative assessment. This chapter describes the approach used to quantify the proposed GridFlorida RTO costs and benefits. RTO benefits are derived from the difference in total system production costs between the existing and proposed markets as a result of the structural and operational changes described in the previous chapter. We note that our reference to the change in total system production costs between the two cases as RTO benefits does not necessarily mean any market restructuring effort will yield benefits. Other structural and operational changes could cause increased production costs. In this study, however, the proposed restructuring of the existing market to a Day-1 RTO or to the Delayed Day-2 RTO resulted in lower total system production costs, hence our reference to the savings as RTO benefits. The other quantifiable aspect of the cost-benefit assessment involves assessment of the change in fixed and operational costs associated with formation of the RTO. A complete analysis of this should examine both the startup and operational cost of forming the RTO and the change in the costs of the existing utility operations as a result of the formation of the new RTO entity. We note, however, that the RTO costing effort in this study examined only the first component, i.e., only the fixed and operational costs associated with forming and maintaining the new entity, and did not examine the second component, i.e., it did not simultaneously examine the change in existing utility fixed and operational costs as a result of the formation of the new entity. Therefore the RTO costs presented in this report do not include any changes in costs associated with existing utility operations or the associated costs of market participants in working with the new GridFlorida RTO and should be interpreted as such.

3.2 Cases Examined

As part of this assessment, ICF reviewed and analyzed a number of varying market structure cases. We believe that our model-based assessment of these market structure scenarios as will be described later in this chapter and in Chapter 4 captures the key physical characteristics of grid operation, the salient demand/supply fundamentals, and the market structure and operational parameters. However, we acknowledge that any model has limitations in terms of perfect simulation of the system and participant behavior, and some parameters are best treated through simplified assumptions which can be further tested or examined through sensitivity cases. As such, ICF was requested by the Project Steering Committee in consultation with the larger Stakeholder group and the FPSC to examine a Reference set of cases and additionally, two sensitivity cases. In total, these cases highlight key parameters and select uncertainties that are relevant in developing the cost benefit assessment.

The Reference Cases consist of three market structure cases:

- A Base Case that reflects the decentralized market as-is with individual company and control area operation, multiple transmission providers and "pancaked" transmission rates for the entire 13 year study period.

- A Day-1 Only Case that reflects decentralized company operation but with a single transmission provider and a single GridFlorida-wide transmission tariff for the 13 year study period.
- A Delayed Day-2 Case that comprises three initial years of Day-1 operation, followed by 10 years of Day-2 operation. Under Day-2 operation, unit commitment and dispatch for the entire Peninsular Florida region is centralized under the GridFlorida RTO and all market participants take transmission service from the RTO under a single tariff.

All three cases (Base Case, Day-1 Case and Delayed Day-2 Case) are collectively described in this report as the Reference Cases. Each case spans a 13-year forecast period, representing the period from 2004 through 2016 in calendar year terms. However, this forecast period is more appropriately referred to as Year 1 through Year 13.

In addition to the Reference Cases, two sensitivity analyses were performed as described below. Because of the relatively low RTO Benefits realized in the Reference Case Day-1 RTO Case, the other two sensitivity analyses described below were conducted for only the Delayed Day-2 case[13,14]. Exhibit 3-1 provides a summary of all the cases modeled.

[13] Note that the Base Case remains unchanged under these two sensitivity analyses.

[14] The final set of sensitivity analysis cases were decided by the Applicants in consultation with Stakeholders after Stakeholder review of the results from the Reference Cases.

Exhibit 3-1
Summary of Cases Analyzed

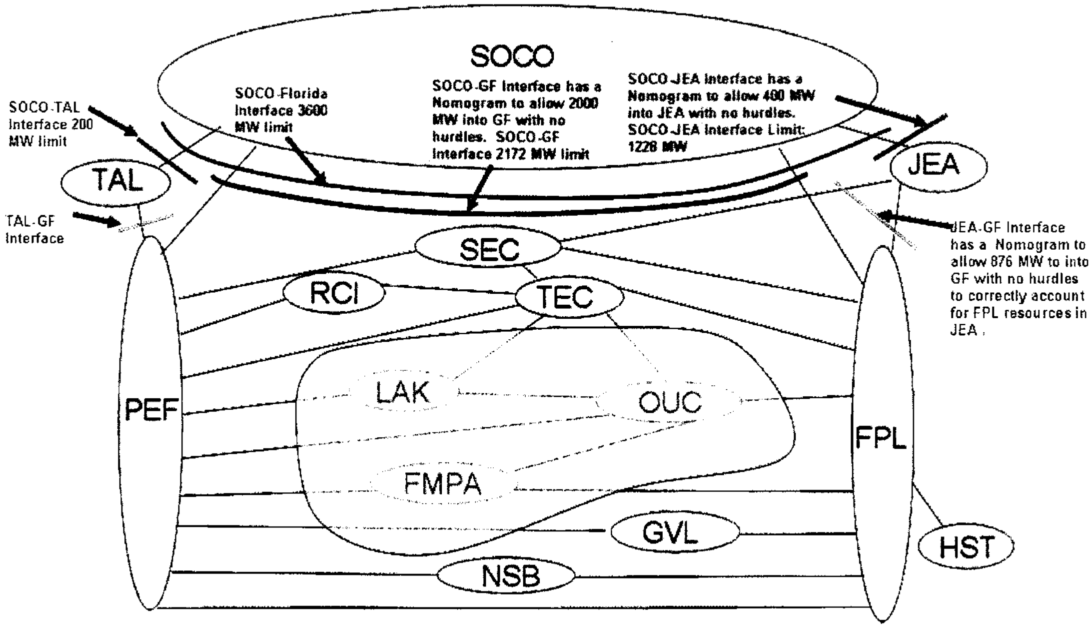
	Base Case	Day-1 Case	Delayed Day-2 Case	Total Number of Cases
Reference Cases	Yes	Yes	Yes	3
Sensitivity Analysis – JEA and TALL Out Case*	Unchanged from Reference Case	Not in Scope of Study	Yes	1
Sensitivity Analysis – Market Imperfection Case*	Unchanged from Reference Case	Not in Scope of Study	Yes	1
Total Number of Cases	1	1	3	5

*Note that the Base Case remains unchanged under these two sensitivity analyses.

JEA and TALL Out Case: The first sensitivity analysis case is associated with the possibility that some utilities may choose not to participate in a GridFlorida RTO. Jacksonville Electric (JEA) and Tallahassee Electric Department (TALL) were chosen for this sensitivity case because of their proximity to Georgia and their previous consideration of joining the now suspended SeTrans RTO. Therefore this case looked at a smaller GridFlorida RTO with JEA and TALL as non-participants. This sensitivity analysis case is subsequently referred to in this study as the JEA and TALL Out Case.

In the JEA and TALL Out Case, the key parameter changes occur in Day-2 with the formation of the proposed GridFlorida RTO and the definition of the new transmission interface between the RTO and the three key adjacent entities – Southern Company, TALL and JEA. Thus, the JEA and TALL out sensitivity analysis was modeled off the Delayed Day-2 Case only. As mentioned earlier, given the low level of benefits projected for Day-1 in the Reference Case, the Day-1 case was not considered in this sensitivity analysis. The Base Case modeling treatment also remained unchanged as part of this sensitivity analysis. Exhibit 3-2 shows a schematic diagram of the reconfigured RTO in Day-2 and the modeled transmission interfaces.

Exhibit 3-2
Schematic Diagram of the Proposed GridFlorida RTO with JEA and TALL as Non Participants



PEF: Progress Energy Florida, FPL: Florida Power & Light Company, TEC: Tampa Electric Company, RCI: Reedy Creek Improvement District, SOCO: Southern Company, JEA: Jacksonville Electric, TAL: City of Tallahassee Electric Department, SEC: Seminole Electric Cooperative, LAK: Lakeland Electric, OUC: Orlando Utilities Company, FMPA: Florida Municipal Power Authority, NSB: New Smyrna Beach, GVL: Gainesville Regional Utilities, HST: City of Homestead

As a result of the new configuration under the GridFlorida RTO, in the Reference Case, power transfers from Georgia incur a single transmission charge to access the wholesale power market in Peninsular Florida. However, in this sensitivity case, in the event the power from Georgia to the GridFlorida RTO flows through either JEA or TALL an additional "pancaked" transmission charge is incurred. We note that the quantitative costs of forming the new RTO as presented in this study (and discussed in the last part of this chapter) remained unchanged under this sensitivity case. However if this total quantitative cost is adjusted for the cost changes associated with changes in existing utility operation, the overall cost of the RTO with JEA and TALL as non participants would change accordingly.

Market Imperfection Case: The second sensitivity analysis addresses load uncertainty and transaction costs. As was discussed earlier, the Base Case incorporated commitment hurdles and dispatch hurdles that were derived through calibrating to actual market outcomes. Thus, certain elements of actual market operation such as load uncertainty and minimum transaction volumes were implicitly taken into consideration. In contrast, however, the Delayed Day-2 Case did not assume any commitment or dispatch hurdles nor incorporate explicit treatment of load uncertainty, unlike real-time operations where load uncertainty necessitates additional generation resource commitment. Since load is known with certainty in these models, unit commitment tends to be more efficient than would be achievable in actual practice. The Delayed Day-2 Reference case also did not consider any minimum transaction volumes or margin between any two transacting entities to buy or sell power. With no established minimum transaction sizes and margin, the volume of trade between counterparties also tends to be more than would be achievable in actual practice. Thus, this sensitivity analysis sought to retain select aspects of actual market operation such as demand uncertainty and minimum transaction blocks. Specifically, demand uncertainty was simulated through committing more megawatts which in turn was simulated through a simplifying assumption of retaining a \$5/MWh commitment hurdle in the Delayed Day-2 Case[15]. Capturing minimum transaction blocks was simulated by retaining a greater dispatch hurdle for power transfer, i.e., 25% of the Base Case

[15] Typically, the inclusion of commitment hurdles results in a greater level of commitment simply because the model is constrained from optimizing across a broader set of units. With a more limited set of units, the actual megawatts committed are likely to be higher as units cannot be partially commitment.

dispatch hurdles up to a $0.5/MWh cap. This sensitivity analysis is subsequently referred to in this report as the Market Imperfection Case.

As mentioned earlier, additional scenarios are certainly possible as there is a range of uncertainty around a number of other market constructs, supply/demand fundamentals, market behavior, etc. However, capturing the full range of uncertainty is somewhat impractical and was outside the scope of the ICF study. Additionally, a number of scenarios would have a low probability of occurring and thus have less relevance. For example, an alternate scenario that was raised in discussion with the Stakeholder Group was one in which there are no commitment and dispatch hurdles between Peninsular Florida and the Southern Company region. Such an alternative would mean all generation resources in Southern's territory are considered network resources in Peninsular Florida; and all of Southern's generation resources combined with Peninsular Florida generation resources are equally eligible to be committed to serve load in Peninsular Florida. Such a scenario did not appear likely mainly because it would not only mean the integration of GridFlorida RTO and Southern Company as a single market but with the suspension of the SeTrans RTO efforts in 2003, it was considered unlikely that that an RTO effort would be started anytime soon. Therefore in consultation with the Project Steering Committee, this alternative scenario was not considered. Thus, all cases modeled in this study retained commitment hurdles between Peninsular Florida and Southern Company (with the exception of the FRCC resources located external to GridFlorida).

3.3 Approach to Estimating RTO Benefits

ICF used GE Energy's Multi Area Production Simulation (MAPS) software model for estimating the benefits associated with transforming the Peninsular Florida market. MAPS is a highly detailed model that chronologically calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. MAPS uses a detailed electrical model of the entire transmission network, along with generation shift factors from a solved power flow case to determine how power from generating plants will flow over the AC[16] transmission network[17]. This feature enables MAPS to capture the economic penalties of re-dispatching generation to satisfy transmission facility limits and security constraints. ICF used MAPS to perform a security constrained unit commitment and economic dispatch of generating resources to meet load and reserve requirements. ICF modeled a 13-year forecast period with 10 explicit model run years. Specifically, ICF modeled Years 1-7, 9, 11, and 13. In calendar years, this is equivalent to 2004-2010, 2012, 2014 and 2016. The outputs of the modeling exercise include power plant dispatch, hourly nodal and zonal prices, fuel use, emissions and power flows on monitored transmission lines and transmission interfaces. These outputs were generated for all the cases referenced in the previous section and will be discussed in greater detail in Chapter 4.

3.4 Model Calibration

A key element of the approach to estimating RTO benefits involves the use of "hurdle rates" to capture potential inefficiencies associated with decentralized markets. Two key inefficiencies associated with the existing Peninsular Florida's decentralized market

[16] Alternating Current

[17] MAPS uses a linearized Direct Current (DC) Network approximation.

are: (i) individual and independent company operation; and (ii) multiple transmission providers, each with its OATT, scheduling and dispatching practices. As described earlier, hurdle rates are a modeling construct that allows us to simulate these aspects of decentralized model operation by imposing an additional cost component, in most cases a significant additional cost component, on resources outside the company control. This naturally provides the economic incentive, within the modeling context, for local company resources to be utilized first ahead of external resources, thereby simulating the current framework for unit commitment and dispatch.

The determination of the appropriate level of hurdle rates is achieved through a detailed model calibration exercise where hurdle rates are introduced in the model to calibrate historical market outcomes with the model simulated outcome. The historical market outcomes used to calibrate the models include a number of parameters such as internal Peninsular Florida generation, net interchange (net power imports/exports), generation by unit type, power prices and power flows across key transmission interfaces over a historical period. Since production cost models are not designed to solve for these hurdle rates, calibration exercises tend to be iterative processes whereby an initial assumption of these hurdle rates is used and refined with each successive iteration until the model outcome is reasonably close to the historical actual market outcome.

In calibrating the model, ICF used commitment hurdles to capture company operation (decentralized operation) and dispatch hurdles to capture the combined effect of "pancaked" transmission rates and additional inefficiencies associated with scheduling and dispatching practices of multiple transmission providers. Without the use of commitment hurdle rates, most production cost models would assume a single region-wide market where all units are equally eligible to commit to serve the region-wide load based on economics. For example a unit in Georgia could be committed to serve load in Peninsular Florida and vice versa to the extent it is economic to do so. The use of commitment hurdles provides the MAPS model with the sophistication to recognize market and operational boundaries such as between Peninsular Florida and Southern Company as well as practices across companies such as FPL, TECO, and PEF, operating separately within Peninsular Florida. During the commitment process, these commitment hurdles ensure that only company resources are committed to meet company load first before becoming available to meet the needs of companies which have resource deficiencies to meet their own load.

The Project Steering Committee in consultation with Stakeholders selected 2003 as a reasonable market year to use to calibrate the model for this study. Therefore, ICF used the 2003 market data provided by Stakeholders for this calibration exercise. Exhibit 3-3 provides a high level overview of the data used for the calibration and the associated sources.

Exhibit 3-3
Summary of Calibration Data

Parameter	Source
2003 Hourly Demand	Applicants and Stakeholders
Existing Generator Cost and Performance	Applicants and Stakeholders
Existing Generator Interconnection Nodes	Applicants and Stakeholders
Operating Reserve Requirements	Applicants and Stakeholders
Existing Transmission Network	Applicants and Stakeholders
Transmission Access Rates	Applicants and Stakeholder OASIS
"Must-Take" Contracts	Applicants and Stakeholders
Voltage Support Facilities	Applicants and Stakeholders
Coal Prices (2003)	Applicants and Stakeholders
Natural Gas Prices (2003)	Applicants and Stakeholders
Oil Prices (2003)	Applicants and Stakeholders
Environmental Policies and Allowance Prices	ICF
2003 Actual Unit Dispatch	Applicants and Stakeholders
2003 Hourly Tieline Flows	Applicants and Stakeholders

Both the commitment and dispatch hurdle rates were determined simultaneously during the calibration exercise. Each iteration of the model provided sufficient information to guide which of the commitment or dispatch hurdles or both needed upward or downward adjustment. Specifically, for each unit within Peninsular Florida, the model determines hourly whether the unit should be committed and dispatched. This is done through a multi-pass commitment process that performs hourly commitment of resources to serve load while simultaneously looking one week ahead[18]. Thus the total number of hours the unit is committed and dispatched (and associated generation) can be imputed for the year. Note that in the model, a unit that is not committed will not dispatch; consequently, the level of commitment (in hours) will always be greater than or equal to the level of dispatch. Through the iterative calibration process, the model's projections for unit commitment and dispatch were compared to actual historical operation especially for units that showed large deviations to determine the appropriate hurdle rate adjustments. For example, if a unit that historically dispatched in 2003 did not dispatch as much in the 2003 calibration model and did not commit as much as would be required to permit the level of historical dispatch, then the commitment hurdle was adjusted. In contrast, if the unit was committed as expected but did not dispatch as much as it actually did historically, then the dispatch hurdles were adjusted.

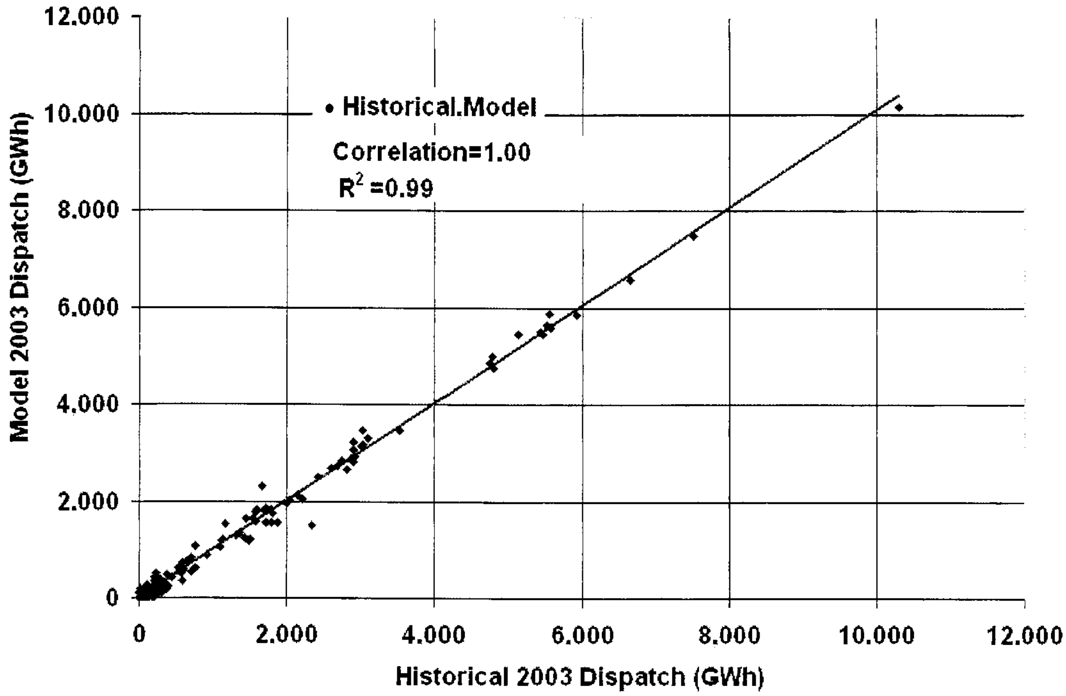
Through this calibration exercise, ICF determined a single commitment hurdle rate across all companies, but a different dispatch hurdle rate for each company-to-company tie-line. These hurdle rates are discussed in Chapter 4. It is theoretically possible for each company to have a different commitment hurdle to ensure its resources are

[18] The forward looking view ensures that each unit's operating characteristics such minimum uptime and downtimes are not violated.

appropriately committed to meet its load but ICF chose to apply a uniform commitment hurdle rate for several reasons. First, the range of rates is not significant and thus a single average number was a reasonable approximation while maintaining simplicity. Second, unlike dispatch hurdles that directly affect dispatch and marginal energy clearing prices, commitment hurdles affect dispatch only indirectly. Specifically, commitment hurdle rates are used as a basis to determine the supply of available resources for dispatch but not as a basis for the production costs for (and thus dispatch of) the units within this supply stack. Production costs are instead a function of variable costs and the dispatch hurdle rate. Finally, we note that ICF is not unique in this aspect of the approach and other cost-benefit studies have applied this similar simplified assumption. Thus ICF concluded that the use of a uniform commitment hurdle for each company was reasonable and validated this assumption by ensuring that the right units were committed for each company, i.e., by ensuring that units belonging to that company/control area were those that were first committed to the appropriate company/control area load.

As discussed earlier, ICF calibrated all generation units in Peninsular Florida and imports across the Peninsula Florida/Southern interface to their 2003 market outcomes. Exhibit 3-4 shows a correlation of 2003 aggregate generation by unit between the model and the actual market. Additional model calibration results are provided in the Appendix B.

Exhibit 3-4
Correlation Between 2003 Actual Generation and the Model Calibration Outcome



3.5 Modeling of the Reference Cases

In modeling the reference cases, there were a large number of parameters that were modeled consistently across all three Reference Cases. These included basic supply/demand fundamentals such as demand levels, physical supply characteristics, fuel prices, environmental allowance prices, etc. See Appendix A. Additionally, the approach to capacity expansion was modeled consistently across all cases, as was the treatment of must-run / must-take contracts. These are described below.

3.5.1 Capacity Expansion

Stakeholders provided their generation and transmission capacity expansion plans for the thirteen-year forecast period for this study through the Project Steering Committee.

This plan was incorporated into each of the annual model runs. Exhibit 3-5 shows the aggregate annual generation expansion plans provided to ICF.

Exhibit 3-5
Stakeholder Generation Expansion Plans Modeled (MW)

Year	Combined Cycle	Cogeneration	Gas Turbine	Coal	Total
2004	1,642	0	0	0	1,642
2005	2,628	0	99	0	2,727
2006	0	210	327	0	537
2007	1,540	0	100	0	1,640
2008	602	0	1,031	0	1,633
2009	1,729	0	180	0	1,909
2010	706	0	725	0	1,431
2011	0	0	1,179	0	1,179
2012	2,582	0	568	150	3,300
2013	1,012	0	871	300	2,183
2014	2,095	0	277	0	2,372
2015	672	0	247	0	919
2016	1,023	0	188	0	1,211
Total	**16,231**	**210**	**5,792**	**450**	**22,683**

Source: GridFlorida Applicants and Stakeholders

3.5.2 Modeling of Contracts

Within Peninsular Florida, ICF did not model any existing economic contracts as the model implicitly optimizes economy energy flows between control areas. Only contracts with must-run or must-take characteristics were explicitly modeled. These contracts were confidentially provided to ICF by Stakeholders. Must-run resources required for voltage support were modeled to have their minimum operating capacity as must run but only for the periods when they are needed for voltage support service. For example if a 250 MW unit with a minimum operating capacity of 125 MW was required to provide voltage support during the peak hours of the summer season, that unit was modeled to provide a fixed minimum of 125 MW in all peak hours of the summer season. The remaining capacity of the unit was available for dispatch based on market economics during that same period. The full capacity of the unit was made available to the generation pool of the associated company for unit commitment and dispatch on an economic basis in all other seasons. Exhibit 3-6 summarizes the aggregate must-run capacity modeled.

Exhibit 3-6
Aggregate Must Run Capacity Modeled

Owner	Unit Name	RMR Capacity (MW)	Summer Capacity (MW)	Seasonality (If Applicable)	RMR Type / Condition
PEF	Anclote 1	90	498	Annual	Voltage
PEF	Anclote 2	90	495	Seasonal	Voltage
PEF	Bartow 1	45	121	Seasonal	Voltage
PEF	Bartow 2	45	119	Seasonal	Voltage
PEF	Bartow 3	90	204	Annual	Voltage
PEF	University of Florida	41	41	Annual	Contract
Calpine	Auburndale 1	132	152	Annual	Contract
FPL	Fort Myers CT 1 & 2	240	298	Annual*	Voltage*
FPL	Lauderdale CC	150	422	Annual*	Voltage*
FPL	Putnam	90	239	Annual*	Voltage*
TOTAL		1,013	2,589		

* These units are Must Run only under specified load conditions.

These must-run assumptions were modeled in all three Reference Cases. Arguably, the need and the amount of must-run capacity could change significantly with the expected change in dispatch from a decentralized operation with "pancaked" transmission charges to a centralized dispatch system. ICF in consultation with the Project Steering Committee and Stakeholders chose to retain the same Base Case must-run assumptions for the Day-1 and Day-2 RTO scenarios because not only did the scope of work not permit a separate AC power flow modeling to estimate the must-run needs of Day-1 and Day-2 operation but such an effort would have greatly expanded the scope of the work.

3.6 Differential Modeling Treatment Across the Reference Cases

There were, however, key structural and operational parameters and constructs that were modeled differentially across the three Reference Cases to capture the alternative market structures. Exhibit 3-7 summarizes the treatment of key parameters in the modeling of the Reference Cases and the major differences across the Reference Cases from a modeling perspective. These major areas of differences are captured through the treatment of:

- Unit commitment and dispatch;
- Transmission rates;
- Operating reserves;
- Losses.

Exhibit 3-7
Summary of Key Differences Across Reference Cases

Parameters	Base Case	Day-1 Case	Day-2 Case
Security Constrained Unit Commitment (SCUC)	Commit to meet control area load plus reserve;		GridFlorida-wide centralized commitment
Security Constrained Economic Dispatch (SCED)	To meet Control Area load plus economy interchange;		GridFlorida-wide centralized dispatch
Transmission Rates	Pancaked transmission rates based on existing control areas	GridFlorida transmission rate based on Day 1 pricing proposal	GridFlorida transmission rate based on Day 2 pricing proposal
Hurdle Rates	H1 – Hurdle designed in model to force unit commitment by Control Area – Applicable only to unit commitment (SCUC) – does not directly affect SCED		None
	H2 – Realized hurdles from model calibration exercise to capture non-tariff related market inefficiencies	None	
Transmission Losses	Based on average losses		Losses priced on the Margin (Marginal Losses)
Operating Reserves	Based on existing FRCC Reserve Sharing Agreement. Each control area provides operating reserves based on their allocation under the Reserve Sharing Agreement		Based on centralized GridFlorida-wide operating reserve market

3.6.1 Unit Commitment and Dispatch

The Base Case model was configured to permit each company to serve its own load. This was achieved by constraining each company's generation resources to serving its load first. Although many of the companies had all their load and resources confined within their control area, some companies either had distributed generation resources serving load that was confined within their control area or had distributed load that was served by generation within their control area. By using the commitment hurdles and operating nomograms, ICF ensured that each company committed its fleet of generation resources to serve its load first regardless of whether that generation or load was located within the geographic boundary of that control area.

3.6.2 Application of the Commitment Hurdles

The application of the commitment hurdles was performed with extreme caution to ensure that the desired effect was achieved i.e., for each company or control area, that least cost units are committed before the more expensive units. In many of the models used for cost benefit analyses such as MAPS, the commitment decision for a generation unit is based on its priority cost. The lowest priority cost generation resource within a control area or within a company's fleet of resources gets committed first to serve its load. In turn, each unit's priority cost is determined by two key components:

- its variable costs[19], and
- its natural location factor[20] with respect to transmission constraints and losses.

[19] The variable cost components of each unit's priority costs include fuel, variable operation and maintenance cost, start-up costs and emissions cost.

When commitment hurdles are introduced in the model as a means to simulate a decentralized market, a third component is introduced to the priority cost equation. This third component, if not properly applied, can introduce distortions to the resultant unit commitment stack. Since the commitment hurdle is designed to constrain a group of generation resources available within a control area or belonging to a company to serve its load, appropriate care should be taken to ensure that the impact of the commitment hurdle is uniform across that target group of resources. These commitment hurdles, if applied across control area tie-lines, can introduce locational biases to the target resources and the effect would be a non-uniform impact of the commitment hurdle across the target resources. For example, assume a particular control area has a single tie with its external electrical world. If a $20/MWh commitment hurdle is placed at this tie, then the impact of the commitment hurdle on each of the units within that particular control area will depend on each unit's shift factor across that tie. Thus, if two units in that control area have different shift factors across this tie, the impact of the commitment hurdle will not be uniform and may distort the priority costs of both units. Thus, an improper application of the commitment hurdle may have the unintended consequence of committing the more expensive generation resource before the cheaper generation resource.

[20] The natural location factor of a generation unit is a measure of its locational advantage or disadvantage with respect to constraints within the transmission system. It is represented by a matrix of the unit's shift factor on all transmission system elements with respect to a designated Reference location on the grid. Thus, all units have their matrix of shift factors. These shift factors change with a change in the Reference Location and/or a change in the grid topology.

Due to this problem, ICF did not apply the commitment hurdles at the control area ties. Instead, ICF used special operating nomograms to uniformly apply the commitment hurdle to each company's units to achieve the dual objective of:

- Constraining units within the company/control area to commit to the control area/company load first before committing to some other load;
- Ensuring that units within each control area/company maintain their true commitment priority derived from their variable costs and their natural location factors.

3.6.3 Application of the Dispatch Hurdles

Dispatch hurdles derived from the calibration exercise were applied between control area ties. These dispatch hurdles are assumed to be primarily associated with scheduling and dispatching operations of multiple transmission providers. In the Base Case, these dispatch hurdles included the transmission rates of each control area as well. For example, if the transmission rate for directional power transfers from TECO to FPL is \$2/MWh and the market inefficiency hurdle between the two entities is \$3/MWh, then the total dispatch hurdle that was applied in the Base Case for direction power transfers from TECO to FPL is \$5/MWh. Note that the \$2MWh transmission rate is the power export rate paid to TECO for power transfers from TECO to FPL. The additional charge paid to FPL i.e., the FPL zonal charge was not explicitly modeled. Since the focus is on wholesale generation production costs, the cost to wheel power within each market zone was not explicitly modeled. In the Base Case, the relevant market zone is each control area. In the Day-1 and Day-2 RTO cases, the relevant market zone is Peninsular Florida. Therefore consistent with the treatment of zonal charges in the base case, the single GridFlorida-wide transmission zonal charge paid in both the Day-1 and Day-2 markets was not explicitly modeled. Thus, the dispatch hurdle between Peninsular Florida control areas was eliminated entirely in both Day-1 and in Day-2 due to the elimination of "pancaked rates" and the elimination of scheduling and dispatching operations of multiple transmission providers. Under both Day-1 and Day-2 operation a single entity is responsible for transmission operations (the RTO) and all market participants take service under a single GridFlorida transmission tariff.

3.6.4 Transmission Rates

Not all transmission providers in Peninsular Florida have published transmission rates. Therefore ICF worked with the Project Steering Committee to determine the transmission rates for use in modeling of the Reference Cases. A uniform transmission rate was assumed for all transmission providers and this rate was derived from the projected revenue requirements of all transmission owning entities in Peninsular Florida. The total revenue requirement was divided by the total projected load of Peninsular Florida to arrive at the transmission rate. The total revenue requirements are slightly different between the Base Case (market as-is) and the RTO Cases (Day-1 and the Delayed Day-2 cases) because of differing treatment of transmission facilities owned by the transmission dependent utilities such as Seminole and FMPA which is explained in detail in Chapter 4. For the most part, however, the transmission rates are similar in both the Base Case and the RTO Cases as shown in Exhibit 3-8.

Exhibit 3-8
Base Transmission Rates

Year	Annual Revenue Requirement (2004 $000s)		Net Energy for Load (GWh)	Base Case Rate (2004 $/MWh)	RTO Case Rate (2004 $/MWh)
	Base Case	RTO Case			
2004	647,687	647,687	226,267	2.86	2.86
2005	683,739	683,739	231,969	2.94	2.94
2006	722,366	722,366	238,870	3.03	3.03
2007	759,047	759,047	244,567	3.11	3.11
2008	793,187	793,187	249,924	3.17	3.17
2009	829,581	830,756	255,534	3.25	3.25
2010	863,368	864,567	261,819	3.30	3.30
2011	900,690	902,487	267,854	3.36	3.37
2012	934,851	937,249	273,993	3.42	3.43
2013	967,066	969,744	280,273	3.45	3.46
2014	999,103	1,001,750	286,622	3.49	3.50
2015	1,036,058	1,037,990	292,968	3.54	3.55
2016	1,066,367	1,068,299	299,555	3.56	3.57

Source: Pricing Team with input from Applicants and Stakeholders.

In the Base Case, the applicable Base transmission rate was used for all transmission entities. In the Day-1 and Day-2 cases, additional transmission charges were added to the Base transmission rate. These additional charges were a Grid Management Charge (GMC) for the new RTO and a levy on all transactions for the first five years to recover the startup cost of forming the new RTO consistent with the amortization plan filed by the GridFlorida Applicants with the FPSC. Ideally, the GMC should be an output of this study but an initial estimate is needed for modeling purposes which could be refined in successive iterations. The scope of the study did not permit this iterative approach therefore the initial estimate was used as a simplification. Thus, the Project Steering Committee estimated the GMC at fixed rate of $0.23/MWh in Day-1 and $0.67/MWh in Day-2. Similarly, the levy on all transactions for the RTO startup cost recovery was $0.08/MWh and $0.18/MWh for Day-1 and Day-2 respectively. Exhibit 3-9 shows the total transmission rate applied in each of the Reference Cases.

Exhibit 3-9
Reference Cases Transmission Rates (2004$/MWh)

Year	Base Case			Day-1 Case				Delayed Day-2 Case			
	Rate	GMC[1]	Total Rate	Rate	GMC[1]	Start Up Cost Amortized Over 5 years	Total Rate	Rate	GMC[1]	Start Up Cost Amortized Over 5 years	Total Rate
2004	2.86	N/A	2.86	2.86	0.24	0.08	3.18	2.86	0.24	0.08	3.18
2005	2.94	N/A	2.94	2.94	0.24	0.08	3.26	2.94	0.24	0.08	3.26
2006	3.03	N/A	3.03	3.03	0.24	0.08	3.34	3.03	0.24	0.08	3.35
2007	3.11	N/A	3.11	3.11	0.24	0.08	3.43	3.11	0.69	0.26	4.06
2008	3.17	N/A	3.17	3.17	0.24	0.08	3.49	3.17	0.69	0.26	4.12
2009	3.25	N/A	3.25	3.25	0.24		3.49	3.25	0.69	0.18	4.12
2010	3.30	N/A	3.30	3.30	0.24		3.54	3.30	0.69	0.18	4.17
2011	3.36	N/A	3.36	3.37	0.24		3.61	3.37	0.69	0.18	4.24
2012	3.42	N/A	3.42	3.43	0.24		3.66	3.43	0.69		4.12
2013	3.45	N/A	3.45	3.46	0.24		3.69	3.46	0.69		4.15
2014	3.49	N/A	3.49	3.50	0.24		3.73	3.50	0.69		4.19
2015	3.54	N/A	3.54	3.55	0.24		3.78	3.55	0.69		4.24
2016	3.56	N/A	3.56	3.57	0.24		3.80	3.57	0.69		4.26

Source: Pricing Team with input from Applicants and Stakeholders.
[1] Grid Management Charge

3.6.5 Operating Reserve Treatment

In the Base Case, ICF modeled operating reserves based on the existing reserve sharing agreement of the Peninsular Florida companies. This reserve sharing agreement mandates a total of 910 MW of operating reserves for the FRCC region. This requirement is derived from the most critical single contingency which is the unplanned outage of the St Lucie nuclear generating unit[21]. This operating reserve requirement is met by all FRCC control areas and allocated based on each control area's peak hour net energy for load in the year 2000, as shown in Exhibit 3-10.

[21] The St. Lucie nuclear unit is a jointly owned unit. Therefore Exhibit 3-10 does not show a 910 MW unit in the "*Capability Largest Unit Gross MW*" column.

Exhibit 3-10
FRCC Operating Reserve Allocation Share

Control Area	2000 Peak Hour NEL MW	Capability Largest Unit Gross MW	Operating Reserve Allocation Percentage	Total Operating Reserve MW	Required Minimum Non-spinning Reserve MW	Minimum Spinning Reserve MW
FMPP	2,950	600	10.40%	98.9	74.2	24.7
FPL	17,808	846	32.01%	291.3	218.5	72.8
GVL	425	235	3.14%	28.6	21.5	7.2
HST	67	9	0.18%	1.7	1.3	0.4
JEA	2,614	518	9.06%	82.5	61.9	20.6
LWU	85	33	0.47%	0.0	0.0	0.0
NSB	88	4	0.16%	1.4	1.1	0.4
PEF	8,694	804	19.96%	181.7	136.2	45.4
RC	68	38	0.51%	4.6	3.5	1.2
SEC	2,553	694	10.94%	99.5	74.6	24.9
TAL	550	250	3.47%	31.6	23.7	7.9
TEC	3,435	480	9.69%	88.1	66.1	22.0
TOTAL	39,337	4,511	100.00%	910	683	228

Source: FRCC

Similar to the Base Case, in the Day-1 Case, the reserve markets will still be under the control of the existing transmission providers and therefore the same spinning reserve criteria modeled in the base case was modeled in the Day-1 scenario as well. However, in the Day-2 Case, the spinning reserve markets are centralized and although the single largest contingency remains unchanged, all spinning reserve-qualified units are eligible to supply spinning reserves based on economics. So in Day-2, the spinning reserve allocation modeled in the Base Case is eliminated while the total requirement remains unchanged. Thus in Day-2, all operating reserve capable resources in Peninsular Florida are committed for operating reserves based on economics.

3.6.6 Treatment of Losses

Another key modeling element that differed among the Reference Cases was in the treatment of losses. Many of the transmission providers in Peninsular Florida have varying treatment of transmission losses. For example some transmission providers have loss charges that vary with the level of transmission facility utilization such as different rates for peak and off-peak transfers while other transmission providers apply uniform loss charges across all transfers. In both the Base Case and the Day-1 case, average losses were modeled since the existing control areas will be responsible for scheduling and dispatching operations, however in Day-2, marginal transmission losses were modeled with dispatching and transmission operations under the RTO.

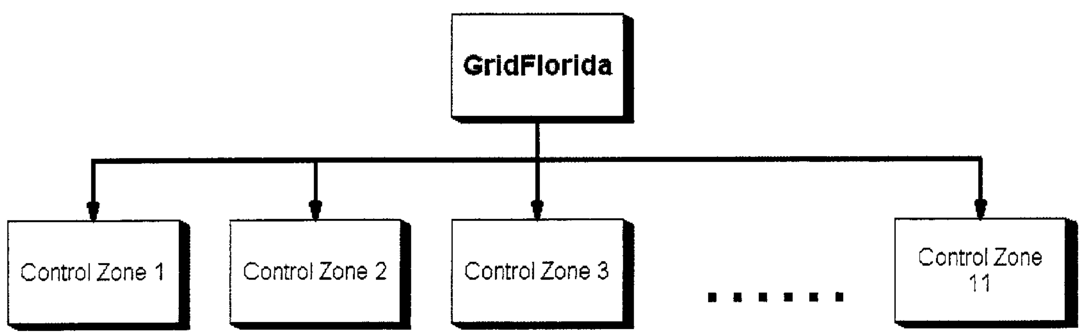
3.7 Approach to Estimating RTO Costs

This section first presents a more detailed overview of the structure of the proposed GridFlorida RTO including a description of the functions and responsibilities assumed under Day-1 and Day-2 operation. Next, these functions are mapped to explicit requirements for the RTO, in the areas of systems, facilities, and personnel. Finally, this section concludes with a discussion of the RTO cost model and the derivation of the underlying cost estimates.

It is important to note that the RTO modeled in this study is a "greenfield" organization with wholly new personnel, physical facilities and systems. That is, none of the existing control area systems, personnel and physical facilities was assumed available to the new RTO. Additionally, the RTO startup and operating costs provided comprises costs associated with the main "greenfield" GridFlorida RTO only. None of the costs of existing Control Zones or potential change in existing utility operational cost from the creation of the new RTO is included in the RTO estimates provided. However all the necessary communication links between the main RTO and the Control Zones are included in the overall RTO cost estimates.

The proposed GridFlorida RTO modeled maintains the essential elements of the hierarchical control area structure proposed in the September 19, 2002 GridFlorida Applicants filing with the FPSC. Under the hierarchical control area structure, the existing control areas are designed as Control Zones operating under a "greenfield" GridFlorida RTO which becomes the substantive control area for the entire Peninsular Florida region. The functional roles and responsibilities between the proposed GridFlorida RTO and the Control Zones were defined for each major activity under both Day-1 operation and Day-2 RTO operation.

Exhibit 3-11
Schematic of the proposed GridFlorida RTO and the Control Zones



ICF worked with the GridFlorida Applicants and Stakeholders to define the functional responsibilities for the RTO and the Control Zones under Day-1 and Day-2 operations. To comply with FERC Orders and to avoid undue discrimination with transmission access under a Day-1 RTO operation, the RTO maintains exclusive responsibility over OATT administration, OASIS, market monitoring, ATC and TTC calculations. The RTO also maintains primary responsibility for both short-term and long-term reliability and security coordination. Under Day-1 operation, there are no GridFlorida-wide markets. Unit commitment and dispatch is decentralized and performed by the Control Zones, i.e., each control zone has primary responsibility for committing and dispatching generation to serve its load while the RTO provides back-up responsibilities. The RTO is also responsible for billing and settlement; however, compared to Day-2, Day-1 billing and settlement needs are minimal and basically related to transmission access.

Under Day-2 operation, the GridFlorida RTO has either primary or exclusive responsibility for all market and control area activities. The Control Zones have secondary responsibilities, but only for selected reliability functions. Exhibit 3-12 provides a detailed listing of functional roles and responsibilities assumed for the RTO and the Control Zones.

Exhibit 3-12
GridFlorida Roles and Responsibilities Summary

X – Full and exclusive responsibility *A – Primary responsibility* *B - Support sole*	Day-1		Day-2	
	GridFlorida RTO	Control Zones	GridFlorida RTO	Control Zones
Grid Operations				
Energy Management System	A	B	X	
ICCP Data Communication System	A	B	X	
Resource Adequacy	A	B	A	B
Planning and Engineering				
Long-Term Reliability	A	B	A	B
Engineering and Facility Studies	A	B	A	B
Interconnection Requests	A	B	A	B
Long Term Activities				
Planning and Expansion	A	B	A	B
Tariff Administration and OATT	X		X	
OASIS	X		X	
Market Monitoring	X		X	
Inter RTO Coordination	A	B	X	
Short Term Reliability	A	B	X	
ATC and TTC Calculation	X		X	
Seasonal Activities				
Congestion Right Allocation and Auctions			X	
RMR Designations	A	B	A	B
Weekly Activities				
Load Forecasting	A	B	A	B
Outage Scheduling	A	B	A	B
Day Ahead Activities				
Day Ahead Market Operations			X	
Day Ahead Reliability Review	A	B	A	B
Day Ahead Ancillary Services Markets			X	
SCUC	B	A	X	
Real-time Activities				
Scheduling and Dispatching Operations (SCED)	B	A	X	
Ancillary Services - Operating Reserves and AGC	B	A	A	B
Security Coordination	A	B	X	
Balancing Function	A	B	X	
Billing and Settlement				
Billing	A	B	X	
Settlement	A	B	X	
Archiving				
Data Storage and Archiving	A	B	X	
Administration				
Customer Interface and Administrative Services	X		X	
Publications and Documentation	X		X	
Operations Support and Training	X		X	
Enforcement	X		X	
Corporate Services and Human Resources	X		X	
Performance Monitoring and Compliance	X		X	
Regulatory Affairs	X		X	
Board of Directors (BOD), Committees and Working Groups	X		X	

3.7.1 Cost Model Architecture (Organizational Design of the GridFlorida RTO)

ICF designed the architecture of the cost model to clearly delineate the Day-1 functions and the incremental functions required for Day-2 operation. This was done to identify the RTO functions that are exclusively Day-1 only, those that are Day-2 only, and those Day-1 functions that require significant incremental investment for Day-2 operation. By identifying each of the functions required for Day-1 and Day-2 operation, ICF was able to design the specific systems and subsystems needed for each mode of RTO operation. ICF identified nine major categories under which functions for Day-1 and incremental functions for Day-2 were grouped.

These categories are as follows:

- Control Center Operations: The Control Center is responsible for real-time balancing of generation and load to maintain system frequency. This functional unit has responsibility for all control center functions such as security coordination, systems operations; energy management, SCADA[22] systems management, interchange coordination with external systems, near-term demand forecasting, OASIS administration and outage scheduling. Control Center operations are required under both Day-1 and Day-2 operations.
- Market Operations: This is the commercial arm of the RTO with responsibility for all commercial transactions. Market operations are largely a Day-2 function with responsibility for all the major markets,

[22] Supervisory Control And Data Acquisition

namely the Day-Ahead and Real-Time markets including ancillary services, and Financial Transmission Rights (FTR) markets. This functional unit is also responsible for billing and settlements. The Market Operations function under Day-1 is minimal and limited to OATT administration, TTC and ATC oversight and some minimal billing and settlement functions primarily for transmission owners.

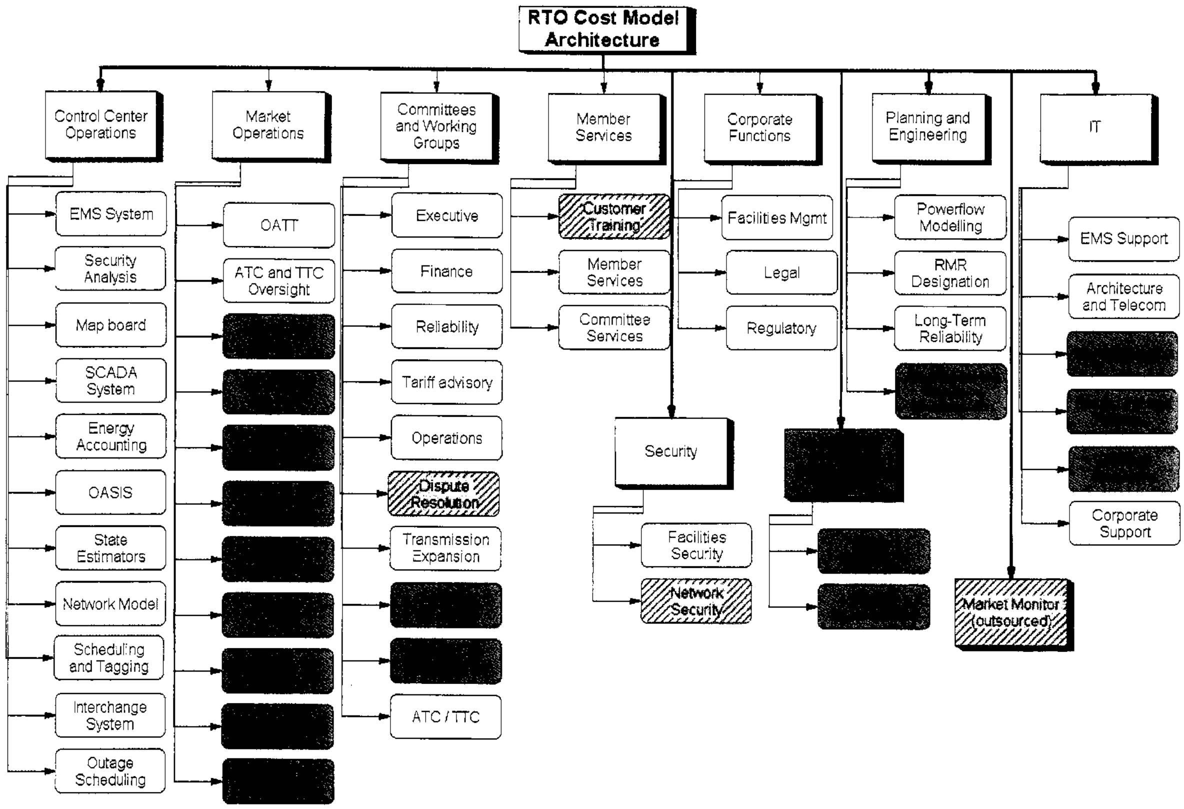
- Committee, Working Groups and Member Services: This functional unit is responsible for providing support for the various RTO working groups. The responsibility of this functional unit increases in Day-2 with the introduction of markets. For example, the number of working groups increases in Day-2 to include congestion management and energy markets.
- Security: This functional unit is responsible for both physical facilities and information security. Responsibilities for this unit include monitoring appropriate access to the GridFlorida facility and confidential data. Information security needs increase significantly under Day-2 operation with the introduction of Day-Ahead and Real-Time markets.
- Corporate Services: This functional unit provides a variety of services for the GridFlorida organization. Responsibilities for this unit include human resources oversight, ongoing recruiting, facilities management, and corporate accounting. Corporate service functions increase with increased Day-2 RTO personnel and functions.
- Planning and Engineering: This functional unit performs all the long term reliability studies and assessment for the RTO. Specifically, the unit is

responsible for power flow modeling, Reliability-Must-Run designation, interconnection studies (transmission and generation), long-term reliability planning, and resource adequacy. This function is needed in both Day 1 and Day 2 RTO operation.

- Information Technology (IT): The IT unit is responsible for providing general corporate IT support as well as the Control Center IT support and EMS system maintenance. In Day-2, this unit's responsibilities increase to include, all market systems and subsystems such as the day-ahead and real-time market systems and the billing and settlement systems.
- Mature Market Functions: This is a Day-2 function and it is designed to explore needs to improve quality assurance and market development for a functional, mature market. Responsibilities include coordination with and study of similar market systems, performance benchmarking, and the evaluation of service or product development opportunities.
- Market Monitoring: Market monitoring needs under Day-1 operation are mainly geared towards ATC and TTC oversight and TLR review. Market monitoring requirements increase in Day-2 with the commencement of day-ahead and real-time markets. Note that for the purposes of this costing exercise, this division is assumed to be fully outsourced and reports directly to the Board of Directors (BOD) in order to maintain objectivity.

Exhibit 3-13 below graphically summarizes the combined Day-1 and Day-2 RTO cost model architecture with a detailed view of exclusive Day-1 and Day-2 functions and those functions with significant incremental investment in Day-2.

Exhibit 3-13
Combined Day-1 and Day-2 RTO Cost Model Architecture



Shaded boxes indicate cost items associated primarily with Day 2 operation

Hatched boxes indicate areas which will incur significant incremental investment to support Day 2

3.7.2 Systems and Physical Facility Requirements

Upon outlining the Cost Model architecture, ICF subsequently derived the system and subsystem requirements and the physical facility requirements for Day-1 and the incremental requirements for Day-2. Exhibit 3-14 summarizes the systems and subsystem requirements for each of the proposed RTO operational modes.

Exhibit 3-14
Systems and Physical Facility Requirements for Day-1 and Day-2 RTO Operational Modes

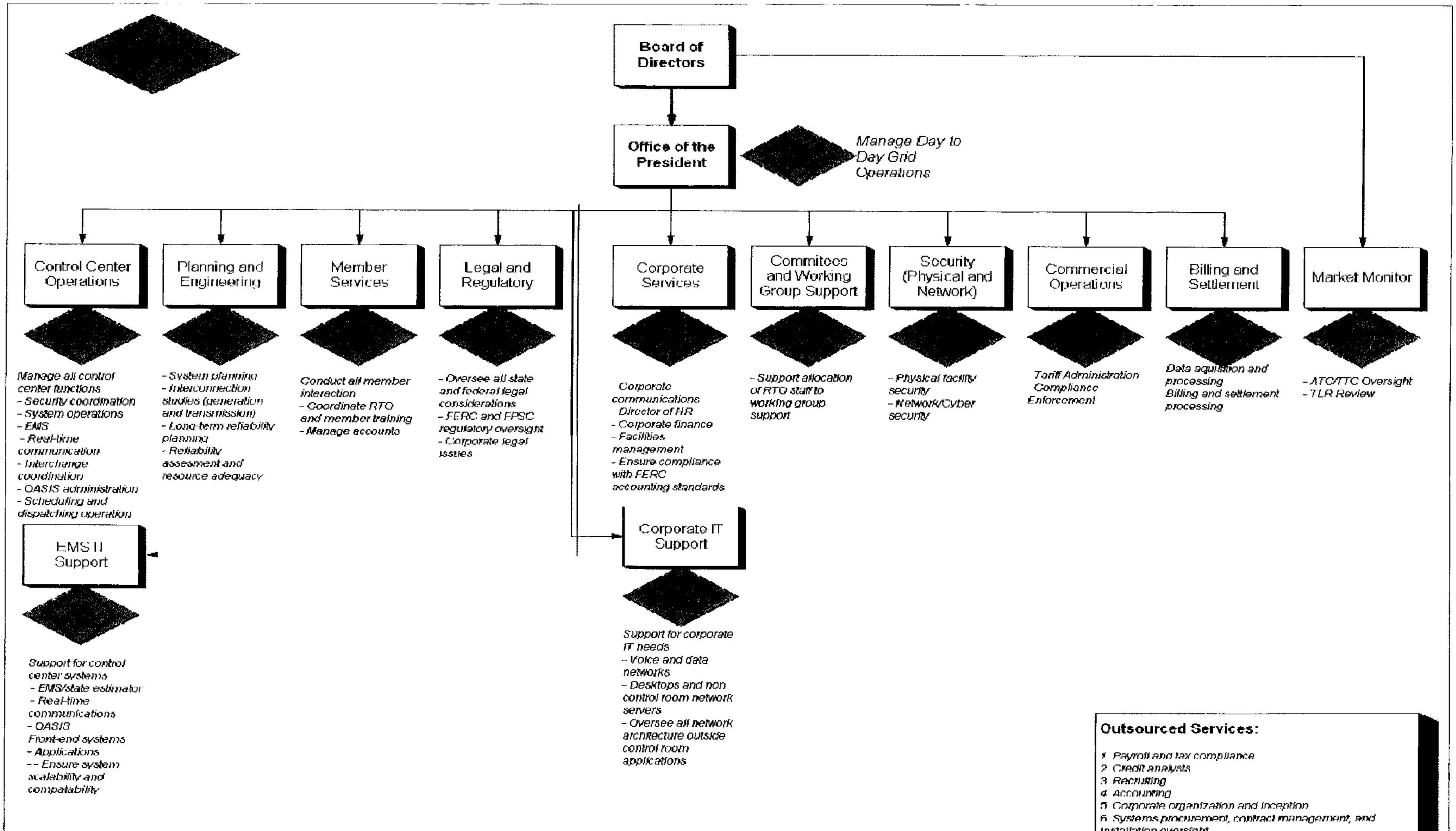
		Day-1	Day-2
Proposed Systems and Subsystems Requirements	EMS System and Applications	√	√
	– State estimator	√	√
	– Network/Power flow model	√	√
	– Security analysis model	√	√
	– SCADA application	√	√
	– Simulation and Training Systems	√	√
	– Hardware support	√	√
	– Annual maintenance	√	√
	Map Board		
	– EMS link	√	√
	– Annual maintenance	√	√
	Communication (ICCP Pathways and Frame Relay) and backup systems	√	√
	Scheduling and Tagging System	√	√
	OASIS (hosted by 3rd party)	√	√
	Compliance with current requirements and OASIS 2A	√	√
	Various transmission models (Load Flow, Production Cost, etc...)	√	√
	Minimal Commercial Operations/Billing and Settlement Software	√	
	Real-Time Market Engine (includes Operating Reserves and AGC markets)		√
	– Bidding and publishing system		√
	– Market clearing engine (MCE)		√
	– EMS Interface		√
	– Settlement interface		√
	– Market database		√
	– Annual maintenance		√
	Day Ahead Market Engine		
	– Bidding and publishing system		√
	– Market clearing engine MCE)		√
	– EMS Interface		√
	– Settlement interface		√
	– Market database		√
	– Annual maintenance		√
	– Real-time market interface		√
	– Reliability assessment		√
	FTR Market Engine (multi-period)		
	– Market database		√
	– Contingency analysis		√
	– Bid/post interface		√
	– Interface to outage schedule and network model		√
	Enhanced Commercial Operations / Billing and Settlement Systems		√
	Simulation and Training Systems – Market system		√
	Backup Control Center (BCC) Systems Market Monitor (outsourced)		√
Physical Facility Requirements	Main Control Center (MCC),	97,000 sq. ft.	139,000 sq. ft.
	– Hardened	√	√
	– Redundant backup generators	√	√
	– Full telecom redundancy	√	√
	– UPS system	√	√
	Back up control center (w/EMS)		
	– 25,000 sq. ft.	√	√
	– Hardened	√	√
	– Redundant Backup generators	√	√
	– Full telecom redundancy	√	√
	– UPS System	√	√

3.7.3 Personnel Requirements

ICF estimated personnel requirements for each activity to be performed by the RTO in both Day-1 and Day-2 and upward aggregated these estimates into Full-Time Equivalents (FTEs). An 18-month ramp-up period was assumed for the necessary preparations from Day-0 to Day-1 operation. The major activities assumed to be performed during this period are recruiting, system procurement and installation, and employee training.

In total, ICF estimated a need for 194 FTEs for a fully functional Day-1 RTO. These FTE's are summarized by division for Day-1 RTO operation in Exhibit 3-15.

Exhibit 3-15
GridFlorida Day-1 RTO Organizational Chart and FTE Count



Source: ICF

The major FTE allocations for Day-1 operation are as follows:

- 51 FTEs are planned for Control Center Operations and will be responsible for services such as security coordination, dispatching system operations, interchange scheduling, outage coordination, OASIS administration and all scheduling and system operation requirements,
- 27 FTEs are planned for IT Services. Since the EMS system is the central system for transmission and dispatching operations and it is also the real time data repository, 14 FTEs out of the 27 FTEs are earmarked to focus on EMS IT support only. The remainder provides Corporate IT support (i.e., general voice and data networks, desktop and laptop coordination, etc.) Note that the EMS system budget does include significant budget for real-time 24-hour vendor support on an ongoing basis (for example, a number of IT services are outsourced).
- 26 FTEs are planned for Corporate Services and these involve activities such as corporate communications, human resources, corporate finance and accounting, facilities management, and general administration.
- 25 FTEs are planned for Planning and Engineering Services. They are responsible for system planning, generation and transmission interconnection studies, long-term reliability planning, and resource adequacy.
- 14 FTEs are planned for Member Services. The Member Services unit is responsible for all member training and account management. Member Services responsibilities increase significantly under Day-2 operation as member interaction ramps-up with market inception.

- 11 FTEs are planned for Legal and Regulatory Services which will include Federal and State legal compliance, FERC and FPSC regulatory compliance and corporate legal issues. The legal staff is responsible for assisting external legal staff in drafting market rules and protocols during inception.
- 9 FTEs are planned for the Day-1 Billing and Settlement division. Under Day-1 operation, billing and settlement activity is limited to processing of transmission related bills.

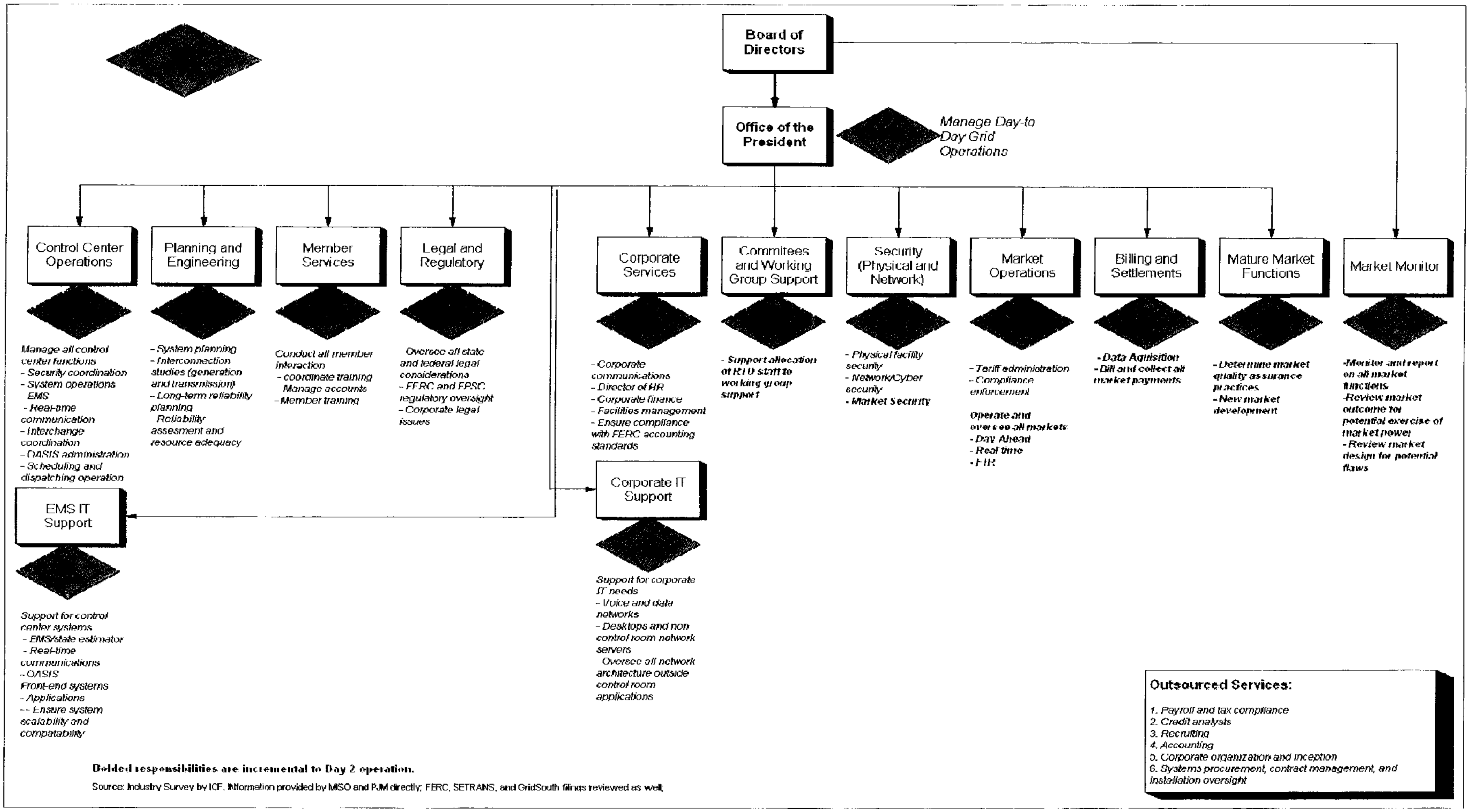
In addition to the 194 Day-1 FTEs many functions are assumed to be outsourced and are therefore estimated in the RTO Cost Model as lump sum expenses. Outsourced functions include market monitoring, payroll and tax compliance, start-up recruiting, accounting, corporate organization and inception, payroll and benefit administration, repro-services, systems procurement contract management and installation oversight, and public relations.

In Day-2, ICF estimates total staffing of 354 FTEs. This represents an incremental 160 FTEs over the Day-1 estimate. In Day-2, the number of FTEs for similar Day-1 functions increases due to increased responsibilities. For example the number of FTEs for Control Center Operations increases from 51 FTEs in Day-1 to 86 FTEs in Day-2 because of increased RTO functions and responsibilities such as coordination requirements with Day-2 markets – energy, regulation, operating reserves and FTR markets. FTE allocations for some of the Day-2 functions are as follows:

- 25 incremental FTEs for Market/Commercial Operations. These FTEs are responsible for the Day-Ahead and Real-Time balancing market operations. Other functions include FTR allocation and auctions and operation of ancillary services markets;

- 12 incremental FTEs for Billing and Settlement. These FTEs are responsible for all commercial billing and settlement activities. Their responsibilities include coordination of payments amongst all participants in the Day-Ahead and Real-Time markets, credit confirmations, and FTR settlement.
- 28 incremental FTEs for IT support. EMS and corporate IT support services increase significantly in Day-2 with the addition of Day-Ahead, Real Time and FTR market systems.

Exhibit 3-16
GridFlorida Day-2 RTO Organizational Chart and FTE Count



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3.7.4 RTO Cost Modeling

After defining the systems, facilities, and personnel requirements for Day-1 and Day-2 operation, ICF proceeded to develop the cost model for the GridFlorida RTO operation. The ICF RTO Cost Model serves to aggregate the resource requirements listed above with detailed cost estimates and financial assumptions necessary to derive an all-in cost estimate for the start-up and annual operation of the proposed GridFlorida RTO. The sections below provide the relevant detail regarding the financial assumptions underlying the RTO Cost Model, and the key cost assumptions and approach.

3.7.5 Financial Assumptions

Financial assumptions were developed through close consultation with the GridFlorida Applicants and Stakeholders. These assumptions were benchmarked against existing data and additional confirmation was also sought from contacts in existing RTOs where possible. Exhibit 3-17 summarizes the key financing assumptions used.

Exhibit 3-17
GridFlorida RTO Financing Assumptions

Parameter	Assumption
Debt/Equity Ratio for Start-up Costs	100/0
After Tax Nominal Equity Rate	N/A
Debt Rate for IDC Expenses	4.2 %
Debt Rate for Startup Costs	5.5 %
Assumed Inflation	2.25 %
Real Discount Rate	3.15 %
Startup Cost Amortization Period	5 Years

- Debt/Equity Ratio: In accordance with Applicant and Stakeholder input, ICF assumed that the proposed GridFlorida RTO start-up costs will be fully funded by loans guaranteed through market participants. This is consistent the current funding of the GridFlorida RTO throughout this evaluation period.

- Debt and Equity Rates: Assuming 100 percent debt financing only the debt rate is relevant. We have assumed debt rates of 4.2 percent for IDC[23] and 5.5 percent for capitalized start-up costs. These are consistent with the 2000-2005 average debt rates realized by A-rated utilities in the US for terms of 18 months and 5 years respectively[24].
- Future Inflation: Future inflation is assumed to average 2.25 percent annually. This is consistent with the 1980-2004 average inflation of 2.26 percent reported by the US Bureau of Economic Analysis[25]
- Discount Rate: The assumed discount rate of 3.15 percent is based on the real WACC[26] for the GridFlorida RTO (corresponding to a 5.5 percent nominal rate, adjusted assuming a 2.25 percent inflation rate). This assumption was benchmarked against the average cost of capital reported by existing US ISOs and the large utilities operating in Florida.
- Start-Up Cost Amortization Period – Start-up costs are assumed to be amortized over 5 years in both Day-1 and Day-2. This is consistent with the original GridFlorida proposal submitted in FERC Docket No. RT01-67 filed on October 16, 2000 and supplemented on December 15, 2000. FERC approved the 5 year amortization in its 3/28/01 conditional approval of the GridFlorida RTO.

[23] Interest During Construction
[24] Source: Bloomberg sample data taken as of Jan. 4 each year.
[25] US Gross Domestic Product - Implicit Price Deflator: Bureau of Economic Activity, Department of Commerce http://www.bea.doc.gov/bea/dn/nipaweb/TableViewFixed.asp#Mid
[26] Weighted Average Cost of Capital

3.7.6 Key Cost Assumptions and Approach

While the RTO Cost Model comprises hundreds of assumptions, a relative few of these have a profound impact on the model outcome. We have given special focus to each of these categories of assumptions, working with industry experts from existing RTOs and ISOs, consulting system vendors and market design experts, and touring existing utility facilities within Peninsular Florida. We summarize these key assumptions below with brief discussions of the methodology and benchmarking underlying each.

- Personnel Costs – Personnel costs were derived from multiple public sources. Base salaries for six broad categories (Executive, Legal, Manager, Skilled, Unskilled, and Administrative) were taken from the Bureau of Labor Statistics (BLS) for the US utility sector[27]. We then inflated the base salaries by the BLS Wage/Benefit package ratio, and added federal social security[28] and payroll taxes[29]. These costs were then benchmarked against actual salary and benefit costs at FPL and PEF as well as aggregate salary information available from the NYISO[30], PJM[31], and ISO-NE[32]. These national average numbers were found to be somewhat lower than current experience within Florida and at existing RTOs indicated. As a result, a 10 percent premium on salaries was included in order to bring our estimates per employee up to the appropriate range. Cost of living data for the three target cities in

[27] Source: All data from U.S. Department of Labor, Bureau of Labor Statistics, National Compensation Survey - Compensation Cost Trends, Employer Cost for Employee Compensation (ECEC), Customized Tables, as of March 11, 2003.
[28] Source: http://www.payroll-taxes.com/PayrollTaxes/00000014.htm
[29] Source: http://www.payroll-taxes.com/PayrollTaxes/00000014.htm
[30] New York Independent System Operator
[31] PJM Independent System Operator
[32] New England Independent System Operator

Peninsular Florida that could potentially host the RTO i.e., Miami, Tampa, and Orlando support a minimum 2-3[33] percent premium over the national average salaries. The remaining premium is based upon benchmarking with existing RTOs and Florida utilities.

- Recruiting, Relocation, and Signing Bonuses – These peripheral personnel costs also added significantly to the RTO Costs, especially in the Day-1 start-up phase. For executives within GridFlorida, recruiting and signing bonuses are estimated to be 33 percent and 15 percent of annual salaries respectively. Relocation expenses are expected to average $42,000 for each of the 44 senior employees of GridFlorida. Recruiting and signing expense estimates are based upon industry literature and a survey of energy industry recruiting firms. Relocation expenses were developed through industry consultation, and benchmarked against FPL and PEF current relocation policies and practices.
- Systems and Subsystems – A large portion of both Day-1 and Day-2 startup expenses are allocated to the acquisition and installation of critical systems necessary to perform RTO functions. Considerable time and effort was spent in building these cost estimates from the bottom up.
    - The single largest line item within the Systems category is the Energy Management System (EMS) estimated at a total of $20 million. This estimate was developed through consultations with EMS vendors familiar with RTO roles and responsibilities, and a

[33] The Average cost of living premium in Tampa, Miami, and Orlando is 2.5 percent according to http://houseandhome.msn.com

detailed review of FPL's recent experience with replacement of an existing EMS system. This estimate includes both hardware and software needs for the Main Control Center (MCC) and the Back-up Control Center (BCC), simulation and training systems, and a budget for any system customizations that may be needed[34].

- Under Day-2 operation significant additional systems expense is incurred to support market operations as well as to support the expanded billing and settlement function. ICF worked closely with representatives from existing RTOs as well as system vendors to accurately estimate hardware, software, and maintenance needs for real-time, day-ahead, and FTR market operations. Billing and Settlement systems were also benchmarked against experiences in PJM, the now defunct GridSouth, the UK, and Ireland as applicable.

- Physical Facilities Costs - The largest physical facility cost component included in the RTO Cost Model is the lease expense for the MCC and the BCC. In determining the amount of office space required, we assumed 250 square feet[35] of office space per GridFlorida employee, with additional square footage allocated for the control room and emergency power facilities. This yields an estimate of 96,500 sq-ft of office space required for the MCC under Day-1 operation, with an incremental 42,000 sq-ft required for Day-2 operation. In addition, we assumed 25,000 sq-ft will be needed for the BCC under both Day-1 and Day-2 operations. All facilities

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[34] Specifically, some customizations may be needed within Florida to account for fast moving weather patterns significantly affecting demand as they pass over the peninsula.
[35] Source: ICF industry survey and literature review

were assumed to lease Class A office space at a cost of $22.8 per square foot[36]. This adds up to a total annual cost of $2.2 million for the main control center under Day-1, $0.57 million annually for lease costs for the BCC, and an incremental $0.96 million for expansion of the main control center under Day-2 operation.

- Soft Facility Costs: Significant expense is budgeted for "soft" facility costs such as facility hardening, office furniture, personal computers, facility design, and voice/data network infrastructure. Each of these line items was estimated using industry standards and in some cases, results of an ICF industry survey.
- Market Monitoring: For ease of estimating market monitoring costs, this function was assumed to be outsourced and performed by a fully separate entity reporting directly to the RTO board of directors (BOD) or the office of the President. The cost assumptions for market monitoring were developed through consultation with appropriate vendors and existing system operators.
- Incremental FERC fees: The FERC is currently mandated to recover all annual operating costs through fees assessed to those entities under FERC jurisdiction. A principal source of revenue recovery is a levy on all "firm sales and transmission activities". In 2003, FERC collected $78 million through a $0.04/MWh fee assessed to IOUs and RTOs throughout the US. As the Peninsular Florida marketplace is transformed into Day-1

[36] Source: This estimate is the average Class A lease cost for Orlando, Miami, and Tampa based on ICF's industry survey. Facilities are assumed to be "build to suit" with a premium for secure/hardened facilities included in the Start-up cost estimate.

and Day-2 operations, ICF expects the number of firm transactions subject to FERC fees to rise significantly as unbundled transmission transactions become more widespread. In developing these estimates, ICF examined recent FERC fees assessed to Investor-owned Utilities (IOUs) operating within Peninsular Florida as well as existing representative Day-1 and Day-2 RTOs. The average percentage of load subject to FERC fees was then estimated for each of the three market structures – Base Case; Day-1 and Day-2.

For the purposes of the cost modeling, the formation of the proposed GridFlorida RTO is planned in three stages:

- Day-0 is the period starting from the time the Applicants and Stakeholders began discussing the formation of the RTO through to the time when a decision is reached to move forward with a Day-1 RTO. The Applicants have provided cost estimates for ongoing Day-0 costs. All costs incurred under Day-0 as part of ongoing operational activities are treated as start-up costs.
- Day-1 startup begins immediately following the final decision to move forward with the GridFlorida RTO. We have assumed the ramp-up period to be 18 months prior to commencement of Day-1 operations, i.e., prior to Year 1. The activities to be performed during the 18 month ramp-up period to Day-1 operation will include facility modification/construction, formation of the BOD, recruiting and hiring, installation of the GridFlorida EMS system and all appropriate communications pathways, system testing and member training. We have assumed that the GridFlorida

system will operate under Day-1 roles and responsibilities for a period of 3 years before roll-out of Day-2 operations.

- Day-2 is the 10 year period following a three year Day-1 operation in the Delayed Day-2 Case. Similarly, we have assumed an 18 month ramp-up period preceding Day-2 operation, during which market rules must be developed, facilities must be expanded, market and settlement systems must be installed and tested, and an incremental 160 FTEs are recruited, hired, and trained.

The detailed results of the RTO costs and benefits modeling based on the approach described in this chapter is presented in Chapter 4.

CHAPTER FOUR
QUANTITATIVE RTO COSTS AND BENEFITS

The quantitative GridFlorida RTO costs and benefits derived from the approach described in Chapter 3 are presented in this section. The results reflect the overall quantitative costs and benefits associated with transforming the Peninsular Florida market from a decentralized operation to either a Day-1 only RTO operation or a Delayed Day-2 RTO operation. The results are presented separately i.e., RTO costs and RTO benefits, and then combined into net costs/benefits for each of the two RTO operating modes. As we have stated earlier, we note that the RTO costs, and accordingly the net costs/benefits, do not reflect the changes in existing utility/control area costs that will result as a consequence of the RTO formation. This is followed by the results of the sensitivity analyses, which are presented separately for each case[37]. Further, the RTO benefits from the Reference Cases are disaggregated into FPSC jurisdictional and non-jurisdictional consumer benefits including transmission cost shifts between jurisdictional and non-jurisdictional transmission providers as a result of a single GridFlorida transmission rate. All figures presented are in 2004 constant dollars unless otherwise stated.

4.1 Summary of Quantitative RTO Costs and Benefits

Exhibit 4-1 shows the summary of the RTO costs and benefits across all cases examined.

[37] Note that the alternative treatment of the external resources in Georgia as non-network resources is only presented for the purposes of comparison to the Reference Case.

Exhibit 4-1
Summary of Quantitative RTO Costs and Benefits (Million 2004$)
NPV (Years 1-13)[38]

Case	RTO Operation	RTO Benefits	RTO Costs[1]	Net Benefit/Costs[2]
Reference Cases	Day-1 Only	71	775	-704
	Delayed Day-2	968	1,253	-285
JEA and TALL Out Case	Delayed Day-2	891	1,253	-362
Market Imperfection Case	Delayed Day-2	810	1,253	-443

[1]Discounted using a 3.15 percent real discount rate
[2]The RTO Costs presented are only costs associated with the new RTO entity. None of the change in existing utility operational costs has been considered in this estimate

A comparison of the quantitative RTO costs and benefits in net present value terms over the 13 year forecast period indicate a loss in all the cases examined before considering qualitative benefits and costs and other utility operational costs and benefits. Whereas the benefits under Delayed Day-2 RTO operation were substantial and ranged from approximately $810 million in the Market Imperfection Case to almost $968 million in the Reference Case, the quantitative startup and going forward operating costs of the wholly new "greenfield" RTO entity with all new systems, personnel and physical facilities is $1.25 billion[39]. Again we note that the RTO costs provided does not include any changes associated with any of the existing utility operational costs as a result of the formation of the new RTO entity. The benefits of a Day-1 only operation were 71 million and the cost of a wholly new "greenfield" Day-1 RTO was 775 million[40]. The Day-1 benefits were small compared to Delayed Day-2 benefits reflecting the fact that the bulk of RTO benefits are derived from centralized unit commitment and dispatch. In Day-1, unit commitment and dispatch are still decentralized so the benefits

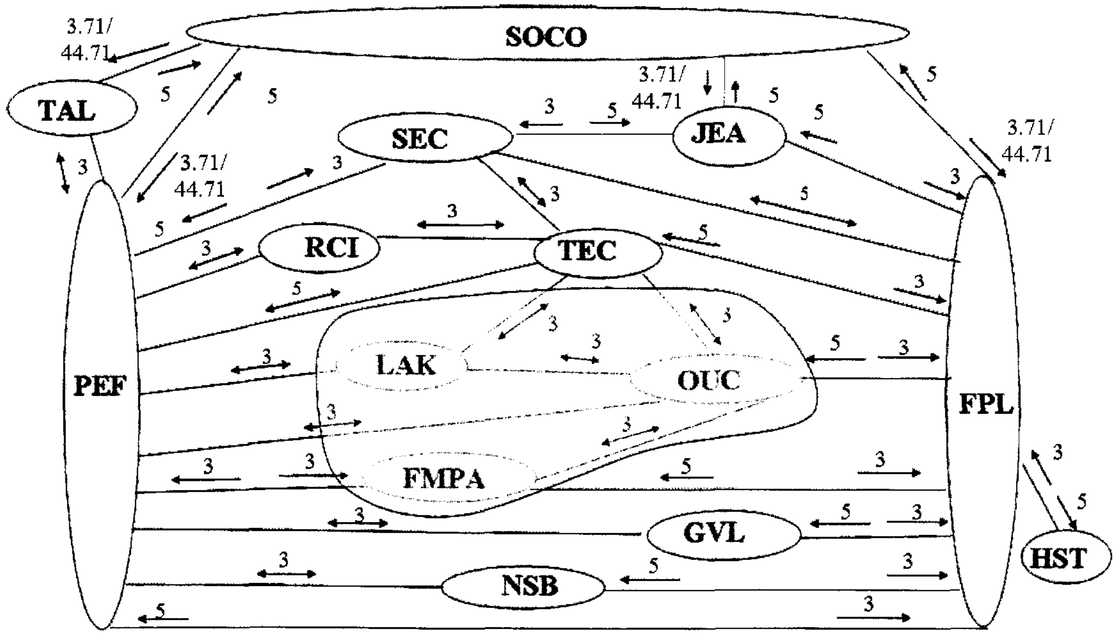
[38] Discounted using a 3.15 percent real discount rate
[39] Includes 33 million of Day-0 costs estimated by the GridFlorida Applicants.
[40] Includes 33 million of estimated Day-0 costs.

are relatively small. The treatment of the UPS contracts as non-network resources reduced the benefits to Peninsular Florida consumers in both the Day-1 Only and the Delayed Day-2 RTO operations. Each of these costs and benefits are discussed in detail below but we begin with a brief discussion of the calibration results used to derive the RTO benefits.

4.2 Model Calibration Results

The commitment hurdle derived from the model calibration exercise was $20/MWh. We believe this relatively high commitment hurdle is reasonable because Peninsular Florida has many control areas and probably the least footprint per control area compared to most other power markets in the continental US. Thus, for modeling, a relatively high commitment hurdle was required to force each control area to commit its units to serve its load first. A set of dispatch hurdles was derived from the calibration effort. These hurdles were applied to the Base Case modeled as part of the Reference Cases. This same set of dispatch hurdles was applied in the JEA and TALL Out and the Market Imperfection sensitivity analyses. Exhibit 4.2 shows the dispatch hurdles used for the various cases. Note that these dispatch hurdles reflect the combined effect of market inefficiencies associated with scheduling and dispatching operations and "pancaked" transmission rates. The relatively high dispatch hurdles in the model associated with the Southern/Florida interface were necessary to constrain imports from the Southern Company region to match the realized 2003 Peninsular Florida import levels and to match the internal Peninsular Florida generation with the 2003 actual generation. The combined dispatch hurdle rate and transmission rate between Peninsular Florida control areas were in the $3/MWh to $5/MWh range. The calibration results indicate a high commitment hurdle and a relatively modest set of dispatch hurdles. This reflects the fact that there are a number of entities within Peninsular Florida performing unit commitment and that some consolidation may provide benefits to consumers. However economic dispatch within Peninsular Florida is relatively efficient, largely because of the high interconnectivity between the control areas and the fact that most transactions are between adjacent systems pay the network transmission rate.

Exhibit 4.2
Dispatch Hurdles for the Base Case Modeled as Part of the Reference Case, and for the JEA and TALL Out Case, and the Market Imperfection Case



PEF: Progress Energy Florida, FPL: Florida Power & Light Company, TEC: Tampa Electric Company, RCI: Reedy Creek Improvement District, SOCO: Southern Company, JEA: Jacksonville Electric, TAL: City of Tallahassee Electric Department, SEC: Seminole Electric Cooperative, LAK: Lakeland Electric, OUC: Orlando Utilities Company, FMPA: Florida Municipal Power Authority, NSB: New Smyrna Beach, GVL: Gainesville Regional Utilities, HST: City of Homestead

4.3 Reference Case Results – Quantitative RTO Benefits

Day-1 Only GridFlorida RTO Operation: The RTO benefits from Day-1 only operation over the 13-year forecast period is $71 million (2004$ NPV). These Day-1 benefits reflect traditional company operation with the primary benefits of Day-1 operation, which is de-pancaked transmission charges. The elimination of pancaked transmission charges is expected to enable more transactions between counterparties, both short-term and long-term. However, the analytical modeling framework used in this exercise is only capable of capturing the benefits associated with incremental short-term transactions. Since, all economy transactions in the model are assumed to be short-term. Long term transactions are only captured if and only if they are explicitly modeled, but since they are generally not known *apriori*, they are not captured in this analysis. Nevertheless, the relatively low level of Day-1 RTO benefits compared to Day-2 RTO is considered reasonable for the following reasons:

- The major source of consumer benefits in Peninsular Florida comes from GridFlorida-wide unit commitment and dispatch, which is only realized under Day-2. Thus, maintaining a decentralized unit commitment and dispatch operation under Day-1, similar to the existing market, is expected to yield only modest benefits;
- Additionally, because there is already a high level of connectivity between control areas in Florida, most transactions occur between adjacent systems. The need for transactions wheeled through multiple systems is typically infrequent and such transactions are generally small. Thus, the benefits of eliminating "pancaked" transmission charges are not as significant.

- Finally, most transmission service provided in Florida is Network Service, as opposed to Point-to-Point Service. Utilities pay for transmission based on their respective load ratio share of the embedded cost of the transmission system, giving them Network Customer priority. As such, their transactions are not subject to additional wheeling charges, so the elimination of such charges would make little difference.

Exhibit 4-3 shows the annual and total Day-1 RTO benefits over the 13 year forecast period.

Exhibit 4-3
Annual Day-1 Benefits (Million 2004$)

Year	Day-1 Benefits
2004	17
2005	5
2006	5
2007	8
2008	5
2009	7
2010	4
2011	3*
2012	3
2013	4*
2014	6
2015	7*
2016	8
NPV (Years 1-13)	**71**

Discounted using a 3.15 percent real discount rate. *Interpolated

<u>Delayed Day-2 GridFlorida RTO Operation:</u> The Delayed Day-2 RTO benefit over the 13-year forecast period is $968 million (2004$ NPV), significantly higher than the Day 1 benefits. This delayed Day-2 benefit comprise three initial years of Day-1 benefits, followed by ten years of Day-2 benefits. Exhibit 4-4 shows the annual and total benefits for the Delayed Day-2 RTO operation.

Exhibit 4-4
Annual and Net Delayed Day-2 GridFlorida RTO Benefits (Million 2004$)

Year	Delayed Day-2 Benefits
2004	17*
2005	5*
2006	5*
2007	106
2008	119
2009	98
2010	95
2011	108**
2012	121
2013	130**
2014	139
2015	139**
2016	139
NPV (Years 1-13)	**968**

*Day-1 RTO operation
**Interpolated
Discounted using a 3.15 percent real discount rate

As mentioned above, the Day-2 benefits are largely derived from centralized unit commitment and dispatch of resources to serve load and reserve requirements, which in turn allows for a much greater level of optimization over a considerably larger set of resources. Mathematically this can be described as decentralized operation yielding local optimums in unit commitment and in dispatch, while centralized operation yields global optimums in both.

4.4 Reference Case Results – RTO Costs

The benefits described above must be compared to costs of achieving them. ICF modeled RTO costs were modeled as Start-up and Operating costs for three developmental stages, with Start-up divided into three categories and Operating costs into two categories:

- Day-0 Start-up Costs: All costs incurred prior to the FPSC decision to proceed with the RTO;
- Day-1 Start-up Costs: Incremental costs to transform the existing decentralized operation to a Day-1 RTO;
- Day-2 Start-up Costs: Incremental costs to transform the RTO from a Day-1 operation to a Day-2 operation.
- Day-1 Operating Costs: Annual expenses associated with operating a Day-1 RTO;
- Day-2 Operating Costs: Annual expenses associated with operating a Day-2 RTO;

Exhibit 4-5 shows estimates of start-up and operating costs for Day-0, Day-1 and Day-2.

Exhibit 4-5
GridFlorida Startup Costs for Day-0, Day-1 and Day-2 Operations (Million 2004$)

Parameter	Day-0 Costs	Day-1 Costs	Day-2 Costs
Costs Incurred Through 12/31/2003	19.0	--	--
Estimated Incremental costs to Day-0	14.4	--	--
Facilities	--	12.2	3.2
Corporate Inception	--	16.8	6.7
Systems	--	33.4	38.3
Operating Costs During Inception	--	40.2	27.2
Day-0 Costs IDC[1]	--	2.2	--
Day-1 Startup Cost IDC[1]	--	5.4	4.0
Total	**33.4**	**110.2**	**79.3**

Total costs incurred through December 31, 2003 in support of the GridFlorida RTO formation is approximately $19 million. These expenses were incurred largely through regulatory filings and feasibility studies by or on behalf of the GridFlorida Applicants. It is expected that an additional $14.4 million will be expended between January 1, 2004 and the final "go" decision on GridFlorida, bringing total Day-0 start-up costs to $33.4 million. All Day-0 cost estimates were provided by the Applicants and reviewed by Stakeholders.

Day-1 startup costs are those expenses necessary to bring the GridFlorida RTO organization from the final "go" decision to operation of the Day-1 RTO. These costs are divided into five broad categories covering:

- $12.2 million in facilities costs that encompass headquarters and Backup Control Center buildings, interim office space, furniture, voice and data infrastructure, backup generators, and facility hardening.
- $16.8 million in corporate inception costs that comprise legal fees, recruiting and relocation expenses, and consultant fees.
- $33.4 million in systems expenses that encompass IT network design, EMS system (HQ and backup) installation, Map board installation, billing and settlement setup, and purchase of various transmission models.
- $40.2 million in operating costs during inception that comprise all employee costs during the 18 month Day-1 ramp-up period.
- $7.6 million in interest during construction (IDC) costs needed to capitalize Day-0 and Day-1 startup costs on the date of operation.

These five broad categories bring the total Day-1 startup cost estimate to $110.2 million incrementally, and $143.6 million when costs to Day-0 are included. Additional detail on start-up costs are provided in Appendix D.

Day-2 start-up costs are those costs expected to be incurred during the period from Day-1 operation to a market-based Day-2 operation. These costs are expected to be incurred during the 18-month ramp-up period to Day-2 operation, and are similarly divided into five broad categories for analysis. Note that all Day-2 costs presented are incremental to Day-1 expenses.

- $3.2 million in incremental facilities costs which include expansion of the headquarters facility, infrastructure, and furniture.
- $6.7 million in incremental corporate inception costs which include recruiting and relocation expenses, consultant fees, and other small items.
- $38.3 million in incremental systems costs which include hardware and software needed for operation of the Day-Ahead, Real-Time, and FTR markets, expansion of the market monitoring function, and expansion of billing and settlement systems needed for Day-2 markets.
- $27.2 million in operating costs during inception that include all employee costs during the 18-month Day-2 ramp-up period.
- $4.0 million in interest during construction (IDC) costs needed to capitalize Day-2 startup costs on the date of operation.

These five broad categories bring the total Day-2 startup cost estimate to $79.3 million incrementally and $222.9 million when Day-0 and Day-1 costs are included. Additional detail on startup costs can be found in Appendix D.

Exhibit 4-6 below provides operating costs for the first year of Day-1 and Day-2 operation. Note that these are different years, since the first year of Day-1 operating costs occur in Year 1 and the first year of Day-2 operating costs occur in Year 4. The Day-2 operating costs provided are incremental to the Day-1 operating costs in that year.

Exhibit 4-6
GridFlorida Operating Costs for First Year of Day-1 Operation and Incremental Costs for First Year of Day-2 Operations (Million 2004$)

Parameter	Day-1 Costs (Year 1)	Incremental Day-2 Costs (Year 4)
Facilities	4.5	1.8
Total Salary and Benefit Cost	30.9	24.1
Systems	5.6	3.1
Outsourced Functions	3.0	4.7
Other/Misc.	5.7	6.8
Capital and Interest Expenses	12.3	9.6
Total Operating Costs	**61.9**	**50.0**

Day-1 operating costs for the first year include all annual operating expenses needed for operation of the GridFlorida RTO under Day-1 roles and responsibilities. ICF's analysis included six broad categories:

- $4.5 million in facilities costs which includes lease expenses for the headquarters and BCC facilities as well as utility expenses for both facilities.
- $30.9 million in salary and benefit expense for GridFlorida employees. This category includes salary, benefit expense, payroll taxes, social security taxes, performance bonuses, and Board of Director expenses.
- $5.6 million in systems costs related to maintenance and license agreements for the EMS and billing/settlement systems, management of the OASIS system, and ICCP[41] link expenses.
- $3.0 million in expenses for outsourced functions such as market monitoring, payroll and benefit administration, external audits, and public relations.

[41] Inter-Control Center Communications Protocol

- $5.7 million in miscellaneous costs such as insurance, taxes, incremental FERC fees, ongoing recruiting and relocation expenses, and business travel expenses.
- $12.3 million in capital and interest expenses which covers interest payments on outstanding loans, as well as ongoing capital replacement budgets. Note that this excludes principle repayment on capitalized startup costs.

These six broad categories bring the total annual operating expense for the GridFlorida RTO in the first year of Day-1 operation to $61.9 million in total.

Day-2 operating costs are divided into the same six broad categories. Note that all Day-2 operating costs are presented as incremental to Day-1 operating expenses.

- $1.8 million in facilities costs which cover additional facility lease costs needed to accommodate new employees and systems and increased facility utility costs.
- $24.1 million in incremental salary and benefit costs for new GridFlorida employees.
- $3.1 million in additional system costs which provides budget for increased data storage needs, and license and maintenance fees for new market and billing systems.
- $4.7 million in incremental costs associated with outsourced functions. These costs support the need for increased market monitoring, payroll and benefit administration, and public relations.

- $6.8 million in miscellaneous costs associated largely with increased FERC fees and insurance.
- $9.6 million capital and interest expenses which cover interest payments on outstanding loans, as well as ongoing capital replacement budgets. Note that this excludes principal repayment on capitalized startup costs.

These six broad categories bring the incremental operating expense of the GridFlorida RTO under Day-2 operation to $50.0 million in the first year of operation. When Day-1 operating costs for the same year are considered, the total operating cost is $109.1 million for the first year of Day-2 operation.

Exhibit 4-7 provides the annual operating expenses for each year of the 13 year forecast horizon for the GridFlorida under Day-1 and Day-2 market structures. Note that all operating costs are presented in real dollars (millions 2004$). Changes in operating costs across years is due to changing interest payments on startup and recapitalization projects, and the underlying assumption of 1% real salary escalation going forward.

Exhibit 4-7
GridFlorida Annual Operating Costs for Day-1 and Day-2 Operations
(Millions 2004$)

Year	Day-1 Costs	Incremental Day-2 Costs	Total Delayed Day-2 Costs
1	61.9	--	61.9
2	61.1	--	61.1
3	60.2	--	60.2
4	59.1	50.0	109.1
5	57.9	51.2	109.1
6	56.6	52.3	108.9
7	57.0	51.9	108.9
8	57.4	51.5	108.9
9	57.9	50.9	108.8
10	58.3	51.3	109.6
11	58.7	51.7	110.4
12	59.2	52.1	111.3
13	59.6	52.5	112.1
NPV (Years 1-13)	640.3	409.8	1,050.2

Note: Excludes principal payments on amortized start-up costs. Discounted using a 3.15 percent real discount rate.

Exhibit 4-8 below shows the annual cash expenditures expected at the GridFlorida RTO through the 13 year forecast horizon. Annual cash expenses start with operating costs, to which is added principal and interest repayment on loans of all startup costs.

Exhibit 4-8
GridFlorida Annual Cash Expenses for Day-1 and Day-2 Operations (Million 2004$)

Year	Day-1 Costs	Incremental Day-2 Costs	Total Day-2 Costs
1	87.6	-	87.6
2	88.2	-	88.2
3	88.8	-	88.8
4	89.3	64.2	153.5
5	89.8	66.2	155.9
6	56.6	68.1	124.7
7	57.0	68.6	125.6
8	57.4	69.1	126.5
9	57.9	50.9	108.8
10	58.3	51.3	109.6
11	58.7	51.7	110.4
12	59.2	52.1	111.3
13	59.6	52.5	112.1
NPV Years 1-13	774.9	477.6	1,252.5

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate

4.5 Sensitivity Analysis Results – JEA and TALL Out Case.

Exhibit 4-9 shows the annual and net benefits from a Delayed Day-2 GridFlorida RTO with JEA and TALL as non participants. The total benefit from this reduced GridFlorida RTO over the 13–year forecast period is $891 million (2004$ NPV) and represents 92% of the $968 million total benefit realized from the larger GridFlorida RTO modeled in the Reference Case. With JEA and TALL as non-participants, approximately 7.5% of the total Peninsular Florida load is excluded from the GridFlorida RTO. The reduced load translates into a lower Delayed Day-2 RTO benefit. Additionally, with JEA and TALL out of a GridFlorida RTO, power imports from the SERC region pay additional transmission wheeling charges when these imports are wheeled through the JEA and the TALL systems, further reducing the overall benefits. Thus the net effect of a JEA and TALL Out scenario is an 8% reduction in the RTO benefits estimated in the Reference Case.

Exhibit 4-9
Annual Delayed Day-2 Benefit – JEA and TALL Out Case (Million 2004$)

Year	Delayed Day-2 Benefits
2004	17
2005	5
2006	5
2007	91
2008	101
2009	90
2010	98
2011	105*
2012	111
2013	121*
2014	130
2015	127*
2016	124
NPV (Years 1-13)[42]	**891**

* Interpolated

4.6 Sensitivity Analysis Results – Market Imperfection Case

Exhibit 4-10 shows the annual and net benefits projected for Day-2 under a Market Imperfection Case. This case incorporated commitment hurdles of $5/MWh and 25% higher dispatch hurdles up to a cap of $0.50/MWh to account for the combined effect of demand uncertainty and transaction costs associated with minimum transaction sizes and margins. The total RTO benefit realized from this case is $810 million (2004$ NPV) which represents 84% of the $968 million in benefits realized in the Reference Case. Thus, up to 16% of the benefits reported in the Reference Cases may not be realized due to these market uncertainties.

[42] *Discounted using a 3.15 percent real discount rate*

Exhibit 4-10
Annual and Total RTO Benefit – Market Imperfection Case (Million 2004$)

Year	Delayed Day-2 Benefits
2004	17
2005	5
2006	5
2007	96
2008	99
2009	82
2010	79
2011	90*
2012	101
2013	104*
2014	108
2015	114*
2016	119
NPV (Years 1-13)	**810**

Discounted using a 3.15 percent real discount rate; * Interpolated

Overall, the Reference Cases and the Sensitivity Analyses indicate that the RTO benefits are mostly significant under Day-2 RTO configuration rather than under Day-1 RTO configuration. While the quantitative benefits of a Day-2 RTO configuration are significant and very large, the quantitative costs of forming and maintaining a Day-2 RTO are even larger. In the next chapter we discuss qualitative factors that should be considered side-by-side with the quantitative benefits and costs presented in this chapter.

Sensitivity of RTO Benefits to the Base Case Commitment and Dispatch Hurdles

ICF performed a sensitivity analysis of Day-1 and Day-2 benefits to the Base Case commitment and dispatch hurdles. These sensitivity analyses were performed off the Year 4 (2007) annual model runs. Two cases were simulated to test the sensitivity of the Day-1 benefits:

- A sensitivity analysis case with each of the dispatch hurdles between Peninsular Florida Control Areas increased by $2/MWh. For example if the dispatch hurdle was $5/MWh in the Reference Case, this was elevated to $7/MWh in this sensitivity case.
- A sensitivity analysis case where the commitment hurdle was cut in half i.e., the commitment hurdle of $20/MWh was reduced to $10/MWh.

The results of this sensitivity analysis are presented in Exhibit 4-11 below and they are compared to the Reference Case Day-1 and Delayed Day-2 benefits.

Exhibit 4-11
Sensitivity of Day-1 Benefits to the Base Case Commitment and Dispatch Hurdles

	Day-1 Benefits Sensitivity of Year 4 (2007) Benefits (Millions 2004 $)	Day-2 Benefits Sensitivity of Year 4 (2007) Benefits (Millions 2004 $)
Base Case Commitment and Dispatch Hurdles as Modeled in the Reference Case	6.5	112.3
Base Case Dispatch Hurdles Increased by $2/MWh	13.1	118.8
Base Case Commitment Hurdles reduced from $20/MWh to $10/MWh	6.5	99.2

These sensitivity analyses results indicate that the Day-1 benefits are largely unaffected by the size of the commitment hurdle but very sensitive to the dispatch hurdles. The Day-1 benefits doubled from $6.5 million to $13.1 million in Year 4 (2007). Thus, over the 13-year forecast period, it is possible that the Day-1 benefits could double from the $71 million realized in the Reference Case to about $140 million. However, since the quantitative costs of a Day-1 RTO is $775 million, even a doubling of the Day-1 RTO benefits would be significantly less than the costs. The Delayed Day-2 RTO benefit increases slightly with the $2/MWh increase in the dispatch hurdles. When the commitment hurdles are reduced by 50%, the Delayed Day-2 RTO benefits decline but by only 12%.

CHAPTER FIVE
QUALITATIVE RTO COSTS AND BENEFITS

5.1 Introduction

The quantitative analysis of costs and benefits did not address all aspects of the impacts of a GridFlorida RTO. This was in large part because there is no agreed upon approach in the industry for assessing some issues. Also, in some cases, the issues are outside the scope of this study.

As explained in more detail in this section, some of these issues include:

- **Investment Efficiency** – The GridFlorida RTO modeling did not assess the impact on investment efficiency. Note between 2005 and 2016, at 2.5 percent demand growth, generation investments in Florida would be roughly $10 billion[43]. Higher demand growth at historical levels and a longer time horizon would raise that above $10 billion and transmission investment would add to this amount. In light of the importance of this issue, most of this discussion focuses on alternative perspectives related to investment efficiency.

- **Bilateral Long-Term Contracting** – The quantitative modeling focused on very short-term spot markets, though over a long time period. Derivative markets such as long-term power sales were not analyzed.

[43] This is calculated by taking the 2004 peak load in Florida of 43 GW, adding a reserve margin of 20%, and growing that requirement by 2.5% per year to determine the number of additional megawatts required. We then multiply that by the average cost per kilowatt of new capacity – we used $600/kW to derive the $10 billion figure Mathematically, this is: [43 GW peak x 1.2 reserve margin x $(1.025)^{11}$ – (43 GW peak x 1.2) current installed capacity] x 600 $/kW cost of new capacity x 1,000,000 kW/GW. We note that the FRCC reserve margin requirement is 15%. However, the three investor-owned utilities (about 77% of FRCC load) have agreed with the FPSC to maintain a 20% reserve margin.

- **Contract Path Scheduling** – The quantitative analysis did not explicitly address the benefits of eliminating contract path scheduling. However, this issue was largely addressed implicitly.
- **Market Power** – The quantitative analysis assumed competitive markets in all scenarios, and hence, possible effects of a GridFlorida RTO on competition were not addressed. This is a complex topic and largely beyond the scope of this study, though some dimensions are briefly identified.
- **Utility Administrative/Operational Cost Analysis** – The direct administrative and operational cost impacts on utilities associated with a GridFlorida RTO are not within the scope of this study.
- **Transition Risks** – The quantitative analysis did not address the potential for operational or financial problems during the transition from the status quo to a GridFlorida RTO.
- **Scope, Organizational, and Regulatory Issues** – There are several organizational issues that arise when a large new organization like a GridFlorida RTO is created. These range from the option value associated with the ability to meet unexpected needs and the potential for unnecessary scope expansion. Regulatory issues may also arise due to the division of jurisdiction between the FPSC, RTO and FERC.
- **Other** - There are several other intangible issues that may apply to the creation of the GridFlorida RTO, including utility return on equity and incentives; management of intra-regional tariffs; efficiency and standards; and merchant power plants.

Each of these items is discussed below.

5.2 Investment Efficiency

The MAPS modeling used to develop the quantitative benefit estimates assumes that there will be considerable investments in new power plants and in electric transmission infrastructure between 2005 and 2016. Within Florida, the applicants and other stakeholders specified these investments, and outside Florida, ICF did so. These investments are especially large in Florida, serving one of the fastest growing populations in the U.S.

However, the level of investments are fixed in the GridFlorida analysis across all scenarios, i.e., across the Base Case and both Day One and the delayed Day Two scenarios. In other words, the quantitative analysis does not estimate the potential impact of GridFlorida RTO on investment efficiency. This applies to both generation and transmission, and contrasts with short-term power plant dispatch and unit commitment, which do vary in the GridFlorida RTO scenarios. This lack of treatment of investment effects in part reflects the lack of methodological consensus on how to model the change in long-term investments in response to the GridFlorida RTO. Furthermore, such a study would significantly increase the scope of the analysis. Hence, a key issue that is discussed qualitatively is the effect of GridFlorida, positive or negative, benefit or cost, on this important aspect of the power sector.

Under GridFlorida RTO, there could be improvements in investment decision-making. This could apply to the siting, quantity and timing of new power plants, transmission lines and other system elements.

There are four main reasons why this might happen under a Day-2 RTO, while under a Day-1 RTO, only the last three apply:

- **Power Price Information** – There is expected to be a very large increase in the amount of power price information under GridFlorida, and potentially a significant improvement in its quality. It is unclear how such an increase would affect transmission investments. The most dramatic change by far would be under Day-2. There are approximately 2,000 nodes or locations in Florida on the high-voltage system[44] for which power prices might become available on an hourly basis. For each location, there would be day-ahead and real-time prices, and hence, 35 million prices per year (8,760 hours times 2 types of prices times 2,000 nodes). In other markets, even more price information is available, as real time prices are calculated as frequently as every few seconds. In addition, there might be prices available for other products such as operating reserves. All of this information would be available to the public, as with MISO, ISO-NE, NYISO, and PJM, at no extra cost above those already estimated.

  The potential value of all this information is that it could provide investment signals for regulators, utilities, investors, and consumers. For example, in the hypothetical case in which nodal prices in southern Florida show significant premiums over northern Florida, these differential could signal the need to site more new power plants, concentrate demand-side management (DSM) programs, or increase fuel delivery capability there, or to increase electric transmission capability to South Florida. In theory,

[44] 69 kV and higher.

prices would reflect marginal generation costs in Florida, grid congestion and marginal transmission losses, although practical experience in existing RTO markets indicates that realized prices are higher than marginal costs. Conversely, a lack of power price differentials in Florida would inhibit potentially excessive investments in transmission and other activities. In any case, under GridFlorida price differentials could become a salient feature of the power situation and an additional benchmark for evaluating investments.

This price information would be subject to market monitoring, and there would be large volumes of transactions underlying the data. In contrast, current power price information is either limited in terms of granularity (hours, locations) or liquidity (few data points).

The impact of such pricing is unclear. While economic theory suggests that such pricing signals would benefit the market, in practice the promise of more efficient investment in RTO markets due to such pricing is unclear. Other mechanisms, such as locational installed capacity markets, and transmission investment incentives have been applied to influence investment decisions in several restructured markets. Where restructured markets have succeeded in encouraging investment, it is unclear whether this is due to more price information or the success of regional planning processes. It may be premature to judge the prospects of better timing and location of generation and transmission due to power price information. In addition, the physical realities of transmission and generation siting and access to fuel are likely to influence near-term marginal pricing signals, suggesting that such price signals are not definitive indicators of asset locations.

- **Elimination of Pancaking** – Pancaking refers to having multiple charges – one for each wheel or utility system crossed - along the contract path of the transaction. In both Day-1 and Day-2, "pancaking" of transmission charges would be eliminated and there would be only one charge for transactions within GridFlorida, regardless of the source and sink location in GridFlorida. This approach aligns the tariff charges for electricity transmission more closely with marginal costs, which are usually lower than tariff rates. If there is no congestion, marginal costs for electric transmission equal losses, which can be a fraction of the tariff charges, especially if several utilities are involved. The quantitative analysis indicates that depancaking will have some effect on operations, but it could also have an effect on investment that is not currently captured. By eliminating pancaking of transmission charges, some utilities would have less incentive to have direct transmission ties to avoid pancaking, and hence, potentially some transmission facilities may be avoided. Also, as a result of de-pancaking, some customers may see an increase in transmission costs while others see a decrease due to cost shifts.

- **Central and Integrated Transmission Planning** – Currently, longer-term planning is carried out separately by each investor-owned and public utility. Under GridFlorida, that planning vis-à-vis transmission might improve in both Day-1 and Day-2, as it becomes centrally coordinated for peninsular Florida as a whole. Recognizing the potential benefits of integrated transmission planning, Florida utilities have taken steps towards a more coordinated planning process at the regional level (FRCC), so some of this potential benefit may be realized without the formation of an RTO.

- **Industry Transparency** – Much of current activity is undertaken by utilities under the jurisdiction of regulatory authorities. This can place large burdens on regulators to review utility activity and information – e.g., ATC calculations, planning analyses, etc. In addition, one of the main drivers behind FERC's activities in promoting RTOs and issuing different orders (e.g., Order 888) is its wish to ensure open and non-discriminatory access to the grid. In this context, having the RTO provide such information is consistent with these objectives. Having said that, there have been no formal complaints filed at FERC regarding the calculation of ATC, or discriminatory treatment. The regulatory burden under an RTO with competitive markets will shift to efforts to ensure these entities with market power do not abuse it, which may result in more regulation. Under a GridFlorida RTO, in addition to public price information, there would be increases in transparency through RTO reports and public information on the grid's condition, planning considerations, etc. A review of RTO websites reveals that these entities publicly provide substantial amounts of such information. Like price information, this increased transparency could improve the efficiency of investments.

No analysis was conducted to assess the adequacy of the Florida transmission system.

5.3 Bilateral Long-Term Contracting

ICF's quantitative analysis of power markets covers a long-term period, i.e., through 2016. However, the cost and benefits analysis was focused on the impacts of creating a GridFlorida RTO on short-term markets, e.g., day-ahead and real time prices. It is expected that the efficiency of these short-term markets will improve relative to the current market, and as a result, could improve the efficiency of longer-term contract and derivative markets as well. No estimate was made of this benefit. In this context, the most common derivative would likely be long-term power sales ranging from several months to several years. These long-term contracts can better manage seller and buyer risks, resulting in less exposure to market volatility and uncertainty. On the other hand, hedging consumer risk with longer term contracts has its own risks as well, since a premium may be paid to secure price stability.

The magnitude of the demand for bilateral long-term contracts in Florida is not insignificant. Florida already has a process for long-term contracting for new plants, including competitive bidding for new power supply. In addition, there are multiple public power entities with a history of long-term contracting. Also, current Florida law limits un-contracted merchants to steam units under 75 MW, and this encourages entities to sign contracts, though the volume might be more if that restriction was less. Also, since there is no retail competition in Florida, the "buy side" demand for such contracts is limited to utility purchases rather than direct purchases. On the other hand, there is a large public power sector acting for consumers.

In some ways, this factor is related to the investment planning discussion above. The more optimal the level of generation and transmission investment, the more long-term contracts may be developed to incorporate this enhanced mix of assets.

5.4 Contract Path Scheduling

Contract path scheduling refers to the practice of assuming that the flows of power in a sale from utility to utility travel via a chosen geographic path, regardless of whether a third utility is affected by what are known as parallel path flows. This can be inefficient, since the third utility might have a more economic use for the transmission capacity, but is unable to utilize it due to other utilities' transactions. This inefficiency would remain to the extent that not all of the utilities in Peninsular Florida participate in GridFlorida. The business as usual case was modeled in GEMAPS without contract path scheduling, and assumed that all Peninsular Florida utilities participate in GridFlorida. GEMAPS models actual path transmission.

Much of the effect of contract path scheduling is captured by the use of hurdles to model inefficiencies in the system in the Base Case. However, it is possible that some inefficiencies were not modeled, and hence, the benefits of the elimination of contract path scheduling in both Day-1 and Day-2 may be understated.

5.5 Market Power

The quantitative analysis assumes perfect competition in both the Base Case and the RTO GridFlorida cases. Market power – i.e., less than perfect competition – is inefficient, and raises equity issues, as margin is transferred form buyers to sellers. Thus, if GridFlorida RTO increases or decreases market power, then it would have additional costs or benefits.

It is unclear whether market power would increase or decrease under a GridFlorida RTO. As more decisions reflect bidding and markets, the level of concentration in the Florida generation sector could increase opportunities for raising prices, since those selling power may tend to bid to supply power at the marginal cost of the next supplier, rather than at their cost. In this context, increasing the reliance on markets could increase wholesale costs.

On the other hand, an RTO will provide full-time market monitoring and the possible sanction of requiring large owners of generation to bid at variable costs if they are deemed to possess or exercise market power. In addition, creating the GridFlorida RTO would separate the operation of transmission from entities which also have generation. Lastly, the existence of price data, centralized commitment and dispatch, and an independent transmission operator might increase competition among participants.

5.6 Utility Administrative/Operational Cost Analysis

The cost analysis was limited to the GridFlorida RTO. However, there are other potential direct administrative/operational costs and benefits (cost savings) at utilities associated with the GridFlorida RTO not included in the cost analysis. On the cost side, utilities could incur training, coordination and other costs to interact with GridFlorida. On the cost savings side, some tasks now handled by the companies or the control zones could be transferred to GridFlorida.

5.7 Transition Risks

ICF's quantitative analysis assumes that the likelihood of operational or financial transition costs is the same across scenarios. Since the RTO will maintain utility control zones, this assumption seems reasonable in the case of operational risks. ICF did not address FTRs or any one participation initial allocation method or FTR market risks to individual market participants. However, there could be unanticipated problems as a GridFlorida RTO begins operations, particularly as utilities learn how to participate in FTR and short-term markets organized that the RTO administer. For example, as participants work with complicated issues such as FTR nominations and bids, they may make decisions that are not optimal, thus spending more than necessary. Thus, there may be risks with changing the structure of the industry and the requirements placed on its participants.

5.8 Scope and Organizational Issues

Several organizational issues can arise from the creation of large organizations like a GridFlorida RTO. On the positive side, the GridFlorida RTO could be a platform for other services – ones not yet contemplated - which may be beneficial. On the other hand, there may be a tendency to scope "creep" – new activities which cost more than they are worth. Another issue is whether not-for-profit entities will have cost controls that are as effective as private companies. Regulatory issues also arise due to question related to the appropriate division of jurisdiction between the FPSC, GridFlorida and FERC. Working through these jurisdictional issues would require time as well as legal and regulatory resources.

5.9 Return on Equity (ROE) and Incentives

There may be different regulatory treatment of utilities and RTOs. This might be a function of state versus federal regulation, which is beyond the scope of this study. FERC might approve higher rates of return for transmission than would the state, which would encourage transmission investments, but also raise rates. FERC has approved higher returns on equity for transmission assets in certain RTOs[45]. Higher ROEs for transmission assets within GridFlorida have not been included in ICF's analysis.

5.10 Management of Inter-Regional Tariffs

The quantitative analysis did not examine the effect of an RTO on inter-regional tariffs. For example, one could argue that if GridFlorida existed, it is more likely that pancaking of tariffs, transmission capacity ("seams), and other problems in relation to neighboring areas could be easier to address. On the other hand, Florida developments might be highly unrelated to developments in the Southern Company and other Southeastern regions.

5.11 Efficiency and Standards

The modeling does not address terms and conditions, procedural streamlining, etc. There are numerous areas where GridFlorida might standardize individual utility terms and conditions that could lower costs. For example, there are significant differences between utilities in the calculation of ATC, and in such areas as the treatment of losses and payment for non-performance in transactions between them. At present, there is little transparency with regard to these factors, and the existence of GridFlorida would help harmonize these differences, and could thus increase predictability and lower risks.

[45] This benefit may only apply to wholesale uses of the transmission system.

5.12 Merchant Power Plants

Some regions of the country have large amounts of capacity in merchant power plants which have no contracts for long-term sales. Rather, they sell into the wholesale spot markets. In contrast, in Florida, merchant plants exist, but generally have long-term contracts. There could be greater new merchant supply if the markets were made more open to spot sales. Currently, the law in Florida is that in order to obtain licensing for new steam power plants larger than 75 MW, they must have secured long-term contracts for their power. Because of changes in spot and merchant activity due to the creation of an RTO, legislative changes might occur if these markets were shown to be more efficient, though continuing to require demand to be demonstrated via contract may still be appropriate.

5.13 Summary of Qualitative Factors

The table below summarizes the potential impacts of each qualitative factor under a Day-1 and Day-2 RTO.

Exhibit 5-1
Potential Impact of Qualitative Factors in Day-1 and Day-2 RTOs

Qualitative Factor	Potential Day-1 Impact		Potential Day-2 Impact	
	Costs	Benefits	Costs	Benefits
Investment Efficiency				
Transmission		√		√
Generation		√		√
Bilateral Long-Term Contracting		√		√
Elimination of Contract Path Scheduling		√		√
Transition Risks	√		√	
Market Transparency		√		√
Scope, Organizational and Regulatory Issues	√		√	
Other factors				
ROE		-		-
Inter-Regional Tariffs		√		√
Efficiency and Standards		√		√
Merchant Power Plants		√		√

CHAPTER SIX
JURISDICTIONAL AND NON-JURISDICTIONAL GRIDFLORIDA QUANTITATIVE RTO COSTS AND BENEFITS

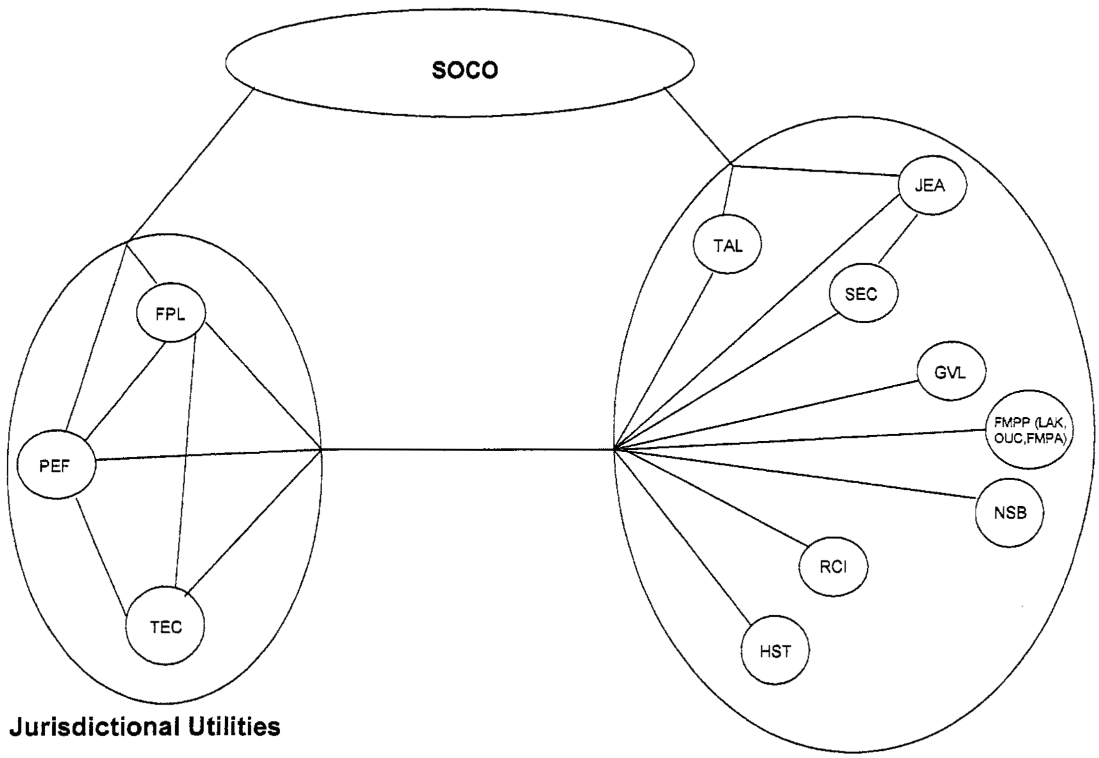
The quantitative RTO costs and benefits from the Day-1 and the Delayed Day-2 cases were disaggregated between consumers of Peninsular Florida jurisdictional and non-jurisdictional utilities. We have referred to the consumers of these utilities as jurisdictional and non-jurisdictional consumers because as ratepayers the costs or benefits associated with the formation of the RTO ultimately accrue to them through their utilities. The jurisdictional consumers are the ratepayers of FPL, PEF and TECO and all other Peninsular Florida consumers are classified as non-jurisdictional consumers. The approach used to disaggregate these costs and benefits is discussed in this chapter. Additionally, we assess transmission owner cost shifts that arise from blending all transmission facilities under the proposed GridFlorida tariff filed by the applicants with the FPSC.

6.1 Allocation of Quantitative RTO Benefits

The approach used to disaggregate the quantitative RTO benefits amongst the two consumer groups has been simplified in this exercise. A more detailed approach would have required additional effort that was not in the scope of the work. Thus, the results of the disaggregated RTO costs and benefits between jurisdictional and non-jurisdictional consumers should be interpreted as an estimate of the allocation rather than a definitive representation of the allocation.

One can think of these two groups as comprising two super control areas in Peninsular Florida with a direct tie line between themselves and, each with a tie line connection with Southern Company. See Exhibit 6-1.

Exhibit 6-1
Re-Configured GridFlorida Market Used For Disaggregating Benefits between Jurisdictional and Non-jurisdictional Consumers



PEF: Progress Energy Florida, FPL: Florida Power & Light Company, TEC: Tampa Electric Company, RCI: Reedy Creek Improvement District, SOCO: Southern Company, JEA: Jacksonville Electric, TAL: City of Tallahassee Electric Department, SEC: Seminole Electric Cooperative, LAK: Lakeland Electric, OUC: Orlando Utilities Company, FMPA: Florida Municipal Power Authority, NSB: New Smyrna Beach, GVL: Gainesville Regional Utilities, HST: City of Homestead

External power imports to the jurisdictional consumers was assumed to flow across the FPL and PEF ties with Southern Company and that to the non-jurisdictional consumers was assumed to flow across the JEA and TALL ties. The direct tie between these two hypothetical super control areas was assumed to be the sum of the existing tie-line capability between jurisdictional and non-jurisdictional control areas.

The jurisdictional and non-jurisdictional consumer groups are assumed to serve their load through a combination of local generation, external imports across the Peninsular Florida/Southern company ties and direct bilateral trades between the two entities. Each consumer group accrues RTO benefits or costs through the changes they adopt to economically serve their load as a result of the change in market structure i.e., from the Base Case to Day-1 only operation or Day-2 operation. The three possible ways each consumer group economically responds to a change in market structure is to:

- change their local power generation;
- change their external power imports;
- change their volume of bilateral power sales/purchases

We illustrate how these quantitative RTO benefits are disaggregated between the two consumer groups using the Delayed Day-2 RTO benefits realized in Year 4 (2007). Exhibit 6-2 shows the annual jurisdictional consumer load is 189,209 GWh and the annual non-jurisdictional consumer load is 55,359 GWh.[46] The jurisdictional consumers increase their local generation from 179,723 GWh in the Base Case at a production cost of approximately $4.71 billion to 181,750 GWh at a production cost $4.77 billion in Day-

[46] See Exhibit 6.2, Line 7

2.[47] Thus, the jurisdictional consumers increase the production costs of their local generation by approximately $56 million. In contrast, the non-jurisdictional consumers generate less power in Day-2 than in the Base Case hence they realize a net saving of approximately $136 million ($1,290,137 - $1,153,332) in production costs.[48] Thus, the combined savings to both parties from internal production costs is approximately $80 million ($136 million - $56 million).[49]

Exhibit 6-2
Disaggregated Day-2 Quantitative RTO Benefits Between Jurisdictional and Non-jurisdictional Consumers – Year 4 (000 2004$)

Line #	Year 4 (2007)	Column A	Column B	Column C	Column D
		Jurisdictional		Non-Jurisdictional	
		Base Case	Day-2 Case	Base Case	Day-2 Case
1	***YEAR 4 PENINSULAR FLORIDA BENEFITS BY CATEGORY***				
2	Total Peninsular Florida Benefits (000 $)	106,000			
3	Component of Benefits from Internal Generation (000$)	80,424			
4	Component of Benefits from Southern Imports (000$)	25,576			
5					
6	***GENERATION AND IMPORTS DATA***				
7	Total Load plus Estimated Losses [50] (GWh)	189,209		55,359	
8	Additional Losses (GWh)	1,976	1,950	427	418
9	Total Internal Generation [51] (GWh)	179,723	181,750	49,473	47,276
10	Southern Imports (GWh)	9,945	10,044	7,830	7,866
11	Total Internal Generation plus Southern Imports (GWh)	189,668	191,794	57,303	55,142
12	Bilateral Import (GWh)	2,672	2,011	1,155	2,647
13	Net Bilateral Import (GWh)	1,517			636
14					
15	***BILATERAL TRANSACTION DETAIL***				
16	Realized Annual Average Bilateral Import Cost ($/MWh)	34.81	32.20	36.24	36.96
17	Total Annual Bilateral Import Cost Without Avoided Costs (000$)	93,021	64,759	41,877	97,829

[47] See Exhibit 6.2, Lines 9 and 29; Col. A and Col. B

[48] See Exhibit 6.2, Line 3

[49] See Exhibit 6.2, Line 3

[50] Takes Seminole's Partial Load requirements and FMPA's load out of FP&L and PEF service territories

[51] Takes into account all the units which are owned by the two parties i.e., jurisdiction and non jurisdiction consumers but excludes firm resources in Southern Co.

18	***Avoided Cost***				
19	Realized Annual Average Alternative Supply Cost ($/MWh)	36.49	34.45	39.05	40.56
20	Annual Average Avoided Cost ($/MWh)	1.68	2.25	2.81	3.60
21	Total Annual Alternative Supply Cost (000$)	97,515	69,284	45,125	107,351
22	Total Annual Saving from Bilateral Imports (000$)	4,494	4,526	3,249	9,523
23	Avoided Import Cost to Net Bilateral Importer (000$)	1,245			4,997
24	50% of Avoided Import Cost Allotted to Buyer (Cost) (000$)	623			2,499
25	50% of Avoided Import Cost Allotted Seller (Gain) (000$)		-2,499	-623	
26	Total Annual Import Cost With Avoided Costs (000$)	93,644	62,260	41,254	100,327
27					
28	***INTERNAL PRODUCTION COST***				
29	Production Cost - GridFlorida (000 $)	4,709,936	4,766,317	1,290,137	1,153,332
30					
31	***EXTERNAL IMPORTS***				
32	Differential in Southern Imports (GWh) - Day 2 minus Base Case	99		36	
33					
34	***SUMMARY***				
35	GridFlorida Production Cost Savings (000 $)	-56,381		136,805	
36	Incremental Saving from External Imports	18,755		6,820	
37	Intra GridFlorida Bilateral Interchange Settlement (000$)	90,457		-90,457	
38	**Total Disaggregated Benefits (000 $)**	52,832		53,168	

However the total Day-2 RTO benefits to all Peninsular Florida consumers in Year 4 is approximately $106 million.[52] Therefore the remaining $26 million of the benefits is associated with external imports from outside the Peninsular Florida region.[53] The residual benefits associated with external imports are distributed between the jurisdictional and non-jurisdictional consumers based on incremental import share and this is discussed later.

Both jurisdictional and non-jurisdictional consumers import power from each other during the year in both the Base Case and the Day-2 Case. In the Base Case, the

[52] See Exhibit 6.2, Line 2
[53] See Exhibit 6.2, Line 4

jurisdictional consumers import a total of 2,672 GWh from the non-jurisdictional consumers in some of the hours of the year and the non-jurisdictional consumers import a total of 1,155 GWh from the jurisdictional consumers in the other hours of the year. Similarly, in the Day-2 Case, the jurisdictional consumers bilaterally import 2,011 GWh and the non-jurisdictional consumers import 2,647 GWh.[54]

In each hour, each exporting party is assumed to serve its load with its least expensive generation first before exporting its relatively more expensive generation. Thus, we determine the average cost of the residual generation exported by the exporting party in each hour and sum that across all hours to determine the total cost of generation exported by each party in each year. In the Base Case, the total cost of bilateral exports of the jurisdictional consumers to the non-jurisdictional consumers was $41.9 million and that of the non-jurisdictional consumers to the jurisdictional consumers was $93 million. Similarly, in Day-2 the total cost of bilateral exports from jurisdictional consumers was $97.8 million and that of the non-jurisdictional consumers was $64.8 million. The implied annual average costs of these exports/imports were determined by dividing the cost by the total generation exported/imported.[55]

It is assumed that the benefits of these bilateral transactions are shared by both transacting entities – the buyer and the seller. Settling these transactions at the cost of the selling entity provides all the benefits of the transaction to the buying entity. Therefore, we estimated the least cost available alternatives to the buying entity should the buying entity forgo the bilateral transaction and we assumed that with perfect market information, both entities will settle the bilateral transaction at a cost that equally shares

[54] See Exhibit 6.2, Line17

[55] See Exhibit 6.2, Line 2.

the margin between the sellers production cost and the buyers alternative power supply cost. In the Base Case, the margin between the jurisdictional consumer imports and their avoided costs is $4.5 million (another $4.5 million in the Day-2 Case) and that for the non-jurisdictional consumer imports and their avoided costs is $3.3 million ($9.5 million in the Day-2 Case).[56] This margin is shared equally and captured as an incremental cost to the buyer but a saving for the seller. Thus, in the Base Case, the jurisdictional consumers import more power than the non-jurisdictional consumers so the net increase in their bilateral import cost is $0.6 million ($4.5 million/2 - $3.2 million/2).[57] This $0.6 million is transferred to the non-jurisdictional consumers as a saving. Similarly, in the Day-2 case, the non-jurisdictional consumers import more power than the jurisdictional consumers so the net increase in their bilateral import costs is $2.5 million ($9.5 million/2 - $4.5 million/2) which is also transferred to the jurisdictional consumers as a saving.[58] Thus, the full cost of the bilateral transaction to each entity is the true production cost plus the additional margin in the case of the buying entity and minus the margin in the case of the selling entity. In the Base Case, the total jurisdictional consumer bilateral import cost is $93.6 million ($93 million + $0.6 million) and the total non-jurisdictional consumer bilateral import cost is $41.3 million ($41.9 million - $0.6 million). Similarly in the Day-2 Case the total jurisdictional consumer bilateral import cost is $62.3 million ($64.8 million - $2.5 million) and the total non-jurisdictional consumer bilateral import cost is $100.3 million ($97.8 million + $2.5 million).[59]

[56] See Exhibit 6.2, Line 22
[57] See Exhibit 6.2, Line 24, Col. A
[58] See Exhibit 6.2, Line 24, Col. D and Line 25, Col. B
[59] See Exhibit 6.2, Line 26 = Line 17 + Line 24+ Line 25

The bilateral import in the Base Case reflects a net cost of $52.3 million ($93.6 - $41.3) to jurisdictional consumers which would reflect a gain to the non-jurisdictional consumers. Similarly the bilateral import in the Day-2 case reflects a net gain of $38.1 million ($100.3 million - $62.3 million) to the jurisdictional consumers which would be a net cost to non-jurisdictional consumers. The net change in bilateral transaction cost to jurisdictional consumers will be the Day-2 cost (-$38.1 million) minus the Base Case cost ($52.3 million). Thus the cost to jurisdictional consumers would be -$90.5 million (-$38.1 million – $52.3 million). This negative cost of -$90.5 million is a gain of $90.5 million to jurisdictional consumers and is also captured as the cost in increased bilateral transaction cost to the non-jurisdictional consumers.[60]

Both consumer groups are net external power importers. The RTO benefits associated with imports into Peninsular Florida is approximately $26 million which is shared between the two consumer groups based on incremental import share.[61] The jurisdictional consumers increased their external imports by 99 MW while the non-jurisdictional consumers increased their external imports by 36 MW.[62] Based on incremental import share, the jurisdictional consumers earned approximately $19 million and the non-jurisdictional consumers earned approximately $7 million.

Therefore the overall RTO benefit to the jurisdictional consumers in Year 4 is the sum of their saving in power imports from the non-jurisdictional consumers ($90.5 million) plus their share of the benefits associated with external power imports ($19 million) minus the increase in their local generation production costs ($56 million). Therefore the net

[60] See Exhibit 6.2, Line 37
[61] See Exhibit 6.2, Line 4
[62] See Exhibit 6.2, Line 32

RTO benefit to the jurisdictional consumers is approximately $52.8 million.[63] This implies that as a result of the change in market structure, the jurisdictional consumers earned $52.8 million in benefits in Year 4 by saving $90.5 million in their bilateral transaction costs (from switching from a net bilateral power importer to a net bilateral power exporter to the non-jurisdictional consumers), and saved $18.8 million from additional external imports but increased generation from their own resources in Day-2 at an incremental production cost of $56.4 million.

Similarly, the quantitative RTO benefit to the non-jurisdictional consumers in Year 4 is the saving in their local generation production costs ($136.8 million) plus their share of benefits associated with external imports ($7 million) minus their cost in reduced power exports to the jurisdictional consumers ($90 million). Therefore the net RTO benefit to the non-jurisdictional consumers in Year 4 is $53.2 million.[64] Thus, as a result of the change in market structure, the non-jurisdictional consumers realized $53.2 million in RTO benefits in Year 4 by saving $136 million in production costs by reducing their local generation and they also saved $7 million by increasing their external imports but lost $90.5 million by becoming net power importers from the jurisdictional consumers in Day-2.

The same procedure was applied to disaggregate the Day-1 RTO benefits between jurisdictional consumers and non-jurisdictional consumers. Exhibit 6-3 shows the disaggregated Day-1 RTO benefits for Year 4. Under Day-1 RTO operation the jurisdictional consumers receive $4.4 million in RTO benefits and the non-jurisdictional consumers receive $3.6 million in benefits.

[63] See Exhibit 6.2, Line 38
[64] See Exhibit 6.2, Line 38

Exhibit 6-3
Disaggregated Day-1 RTO Benefits Between Jurisdictional and Non-jurisdictional Consumers – Year 4 (000 2004$)

Line #	Year 4 (2007)	Column A	Column B	Column C	Column D
		Jurisdictional		Non-Jurisdictional	
		Base Case	Day-1 Case	Base Case	Day-1 Case
1	***YEAR 4 PENINSULAR FLORIDA BENEFITS BY CATEGORY***				
2	Total Peninsular Florida Benefits (000 $)	4,403			
3	Component of Benefits from Internal Generation (000$)	3,615			
4	Component of Benefits from Southern Imports (000$)	8,018			
5					
6	***GENERATION AND IMPORTS DATA***				
7	Total Load plus Estimated Losses [65] (GWh)	189,209	189,209	55,359	55,359
8	Additional Losses (GWh)	1,976	2,033	427	456
9	Total Internal Generation [66] (GWh)	179,723	178,701	49,473	50,569
10	Southern Imports (GWh)	9,945	9,961	7,830	7,826
11	Total Internal Generation plus Southern Imports (GWh)	189,668	188,662	57,303	58,395
12	Bilateral Import (GWh)	2,672	3,423	1,155	843
13	Net Bilateral Import (GWh)	1,517	2,580		
14					
15	***BILATERAL TRANSACTION DETAIL***				
16	Realized Annual Average Bilateral Import Cost ($/MWh)	34.81	34.73	36.24	36.33
17	Total Annual Bilateral Import Cost Without Avoided Costs (000$)	93,021	118,881	41,877	30,646
18	***Avoided Cost***				
19	Realized Annual Average Alternative Supply Cost ($/MWh)	36.49	36.42	39.05	39.34
20	Annual Average Avoided Cost ($/MWh)	1.68	1.68	2.81	3.00
21	Total Annual Alternative Supply Cost (000$)	97,515	124,644	45,125	33,178
22	Total Annual Saving from Bilateral Imports (000$)	4,494	5,763	3,249	2,532
23	Avoided Import Cost to Net Bilateral Importer (000$)	1,245	3,231		
24	50% of Avoided Import Cost Allotted to Buyer (Cost) (000$)	623	1,616		
25	50% of Avoided Import Cost Allotted Seller (Gain) (000$)			-623	-1,616
26	Total Annual Import Cost With Avoided Costs (000$)	93,644	120,497	41,254	29,031
27					
28	***INTERNAL PRODUCTION COST***				
29	Production Cost - GridFlorida (000 $)	4,709,936	4,671,299	1,290,137	1,324,372

[65] Takes Seminole's Partial Load requirements and FMPA's load out of FP&L and PEF service territories

[66] Takes into account all the units which are owned by the two parties i.e., jurisdiction and non jurisdiction consumers but excludes firm resources in Southern Co.

30			
31	***EXTERNAL IMPORTS***		
32	Differential in Southern Imports (GWh) - Day 2 minus Base Case	16	-4
33			
34	***SUMMARY***		
35	GridFlorida Production Cost Savings (000 $)	38,638	-34,235
36	Incremental Saving from External Imports	4,820	-1,205
37	Intra GridFlorida Bilateral Interchange Settlement (000$)	-39,076	39,076
38	**Total Disaggregated Benefits (000 $)**	4,382	3,636

Overall the jurisdictional consumers earn 42% of the benefits and the non-jurisdictional consumers earn 58% of the Delayed Day-2 RTO benefits on an NPV basis. Exhibit 6-4 shows the disaggregated benefits for the two consumer groups for the Day-1 RTO and the Delayed Day-2 RTO operation for each year of the 13 year forecast period.

Exhibit 6-4
Jurisdictional and Non-jurisdictional Day-1 and Delayed Day-2 RTO Benefits. (Million 2004$)

Year	Day-1 Benefits		Delayed Day-2 Benefits	
	Jurisdictional Consumers	Non-jurisdictional Consumers	Jurisdictional Consumers	Non-jurisdictional Consumers
2004	16	1	16	1
2005	1	4	1	4
2006	2	3	2	3
2007	4	4	53	53
2008	1	4	49	69
2009	0	7	33	66
2010	-5	9	36	59
2011*	-5	8	40	68
2012	-5	8	44	77
2013*	-4	8	53	78
2014	-3	9	62	78
2015*	-10	17	64	76
2016	-17	25	65	74
NPV (Years 1-13)	-11	82	411	557

Discounted using a 3.15 percent real discount rate; * Interpolated

The non-jurisdictional consumers realize most of the Day-1 RTO benefits. In NPV terms, the non-jurisdictional consumers earn $82 million but the jurisdictional consumers incur a loss of $11 million. Similarly, the non-jurisdictional consumers earn the bulk of the Delayed Day-2 RTO benefits. In NPV terms, the jurisdictional consumers earn $411 million (42%) of the Delayed Day-2 RTO benefits while the non-jurisdictional consumers earn $557 million (58%). Exhibit 6-5 shows the actual imports in each case and Exhibit 6-6 shows the incremental jurisdictional consumer imports.

Exhibit 6-5
Jurisdictional Utility Power Imports and Exports from Non-Jurisdictional Consumers in the Base Case, Day-1 RTO Case and Delayed Day-2 RTO Case

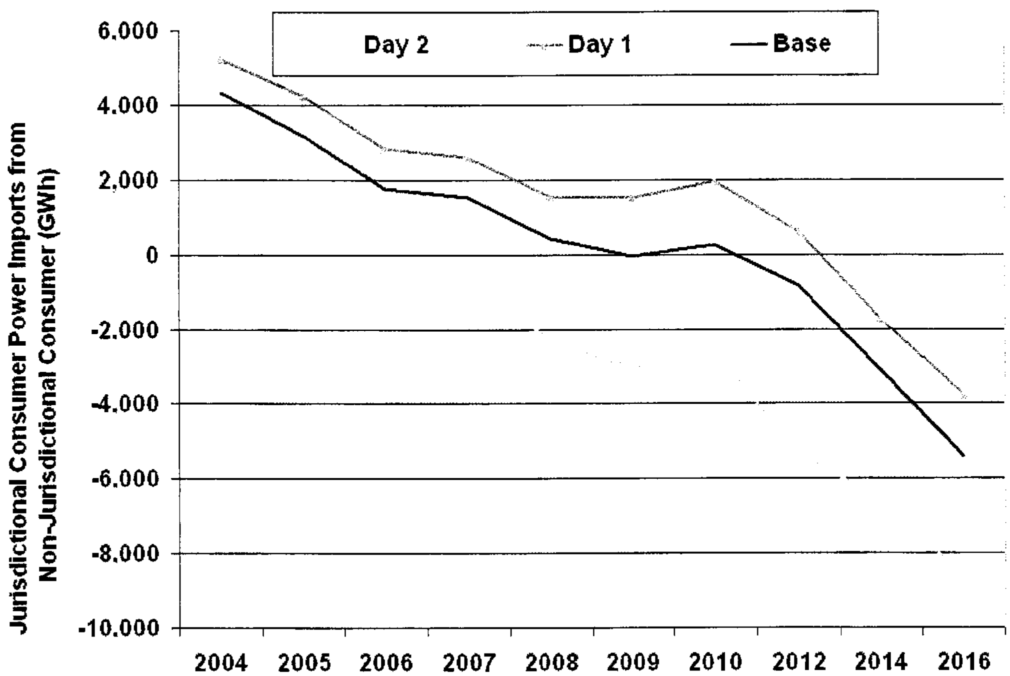
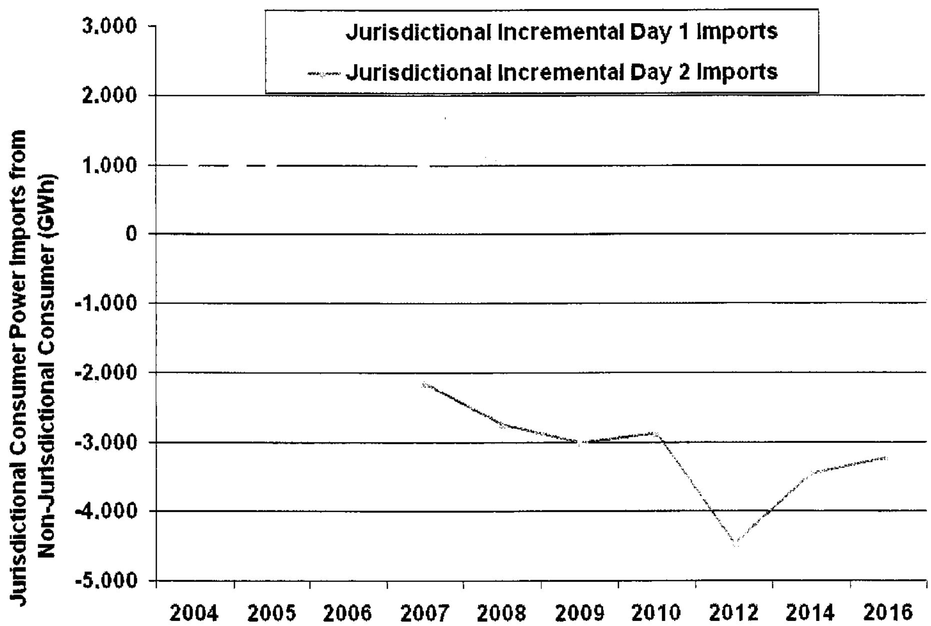


Exhibit 6-6
Incremental Jurisdictional Consumer Power Imports from Non-Jurisdictional Consumers in Day-1 and Delayed Day-2 RTO Cases



Additional disaggregated benefits results for each year is provided in Appendix E for both the Delayed Day-2 RTO Case and the Day-1 RTO Case.

6.2 Allocation of RTO Costs

The RTO costs were allocated to Jurisdictional and non-jurisdictional consumers based on their respective load ratio share. Of the total GridFlorida load, the share of the jurisdictional consumer loads is approximately 77%[67] and the non-jurisdictional consumer load share is 23%[68]. Using these percentages, the Day-1 and Delayed Day-2 RTO costs were allocated to the two groups. Exhibit 6-7 shows the disaggregated costs

[67] This is derived by dividing the 2004 jurisdictional consumers energy requirements by the GridFlorida (jurisdictional and non-jurisdictional) total energy requirements for 2004 i.e. [77%= 175,012GWh/ (175,012+51,255) GWh)]. The energy requirements were provided by GridFlorida applicants and stakeholders.

[68] This is derived by dividing the 2004 non-jurisdictional consumers energy requirements by the GridFlorida (jurisdictional and non-jurisdictional) total energy requirements for 2004 i.e. [23%= 51,255GWh/ (175,012+51,255) GWh)]. The energy requirements were provided by GridFlorida applicants and stakeholders.

for the two consumer groups for the Day-1 only RTO and the Delayed Day-2 RTO for each year of the 13 year forecast period based on their load ratio share in each year.

Exhibit 6-7
Jurisdictional and Non-jurisdictional Day-1 and Delayed Day-2 RTO Cash Expenses (Million 2004$)

Year	Day-1 RTO Costs		Delayed Day-2 RTO Costs	
	Jurisdictional	Non-Jurisdictional	Jurisdictional	Non-Jurisdictional
2004	68	20	68	20
2005	68	20	68	20
2006	69	20	69	20
2007	69	20	119	35
2008	70	20	121	35
2009	44	13	97	28
2010	44	13	97	28
2011	44	13	98	29
2012	45	13	84	25
2013	45	13	85	25
2014	45	13	85	25
215	46	14	86	25
2016	46	14	86	26
NPV (Years 1-13)	$599	$176	$968	$284

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate.

Exhibit 6-8 shows the net benefits in (2004$ NPV) to both jurisdictional and non-jurisdictional consumers.

Exhibit 6-8
Summary of Jurisdictional and Non-jurisdictional Consumer Day-1 and Delayed Day-2 RTO Costs and Benefits (2004 Million$)

NPV (Years 1-13)	Day-1 Only Operation			Delayed Day-2 Operation		
	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit
RTO Benefits	-11	82	71	411	557	968
RTO Costs	599	176	775	969	284	1,253
Net Benefits	-610	-93	-704	-558	274	-285

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate.

Thus, under Day-1 RTO operation, both jurisdictional and non-jurisdictional consumers incur losses. The jurisdictional consumers incur almost 87% ($610 million) of the GridFlorida-wide consumer loss and the non-jurisdictional consumers incur 13% ($93 million) of the loss. Under Delayed Day-2 RTO operation, the jurisdictional consumers incur a loss but the non-jurisdictional consumers earn a benefit. The loss to jurisdictional consumers ($558 million) is almost twice the GridFlorida-wide loss of 284 million. The gain to non-jurisdictional consumers is $274 million.

6.3 Transmission Owner Cost Shifts

Currently, the annual revenue requirements of transmission owners in GridFlorida are recovered under wholesale transmission rates and bundled retail rates. The proposed GridFlorida RTO tariff filed by the GridFlorida Applicants with the FPSC is designed to ensure that the GridFlorida RTO will be able to fully reimburse the annual revenue requirements of the GridFlorida transmission owners. In turn, Transmission Owners will be required to purchase transmission from the GridFlorida RTO in order to meet native load obligations. If the expense the transmission owner incurs to purchase transmission service on behalf of native load customers is greater than the transmission owner's revenue requirements in bundled rates, then there is a cost increase, or shift. Except for the loss of "pancaked" transaction revenue in years six through ten, the sum of the GridFlorida Transmission Owner's revenue requirements are unchanged. Therefore, cost shifts arise from the change in the allocation of the revenue requirements among the various transmission users.

In order to mitigate these cost shifts, the RTO tariff provides a gradual phase-out of individual system pancaked rates to a single GridFlorida-wide system rate. Under a single GridFlorida transmission rate, the revenue requirements of all transmission owners will be recovered from all Load Serving Entities (LSEs) serving load in Peninsular Florida based on their load ratio share. Although the total transmission revenues to be collected from LSEs are designed to be adequate to meet the total revenue requirements of all Peninsular Florida transmission owners, cost shifts occur between the transmission owners as the revenue requirements of all transmission facilities are blended into a pool under a single system rate. Cost shifts occur when utilities invest at a lower rate on a per kW basis than others, when the embedded costs of higher cost utilities are blended with lower cost utilities, and when costs of Transmission Dependent Utilities facilities are included in transmission rates.

Under the proposed GridFlorida tariff filed by the GridFlorida Applicants with the FPSC in March 2004, the Applicants proposed specific mechanisms to phase-in cost shifts and each one of them is discussed below:

> Phasing in to System-wide or "Postage Stamp" rates: The tariff provides for a phase-in to a single system-wide rate in the first nine years of operations. Initially in years one through five, existing transmission facilities (those transmission facilities in service as of 12/31 of the year before the GridFlorida RTO begins commercial operations) are recovered through zonal rates and all new facilities are recovered through the system rate. Zones are set based on the current transmission providers' transmission service area.

During years one through nine, all transactions that sink in GridFlorida[69] bear a zonal charge and a system charge. The applicable transmission owner's zonal rate is applied to all transactions that sink in its zone. The system rate is applied to all transactions.

During years six through ten, the revenue requirements of existing facilities are moved out of zonal rates and into the system rate at 20% per year such that all revenue requirements are recovered in the system rate beginning in year 10.

Exhibit 6-9
GridFlorida Revenue Requirements Under "Pancaked" Transmission Rates and Under the Proposed GridFlorida Tariff

(Thousands 2004$)

Year	Existing Facilities		New Facilities	Total	
	Base Case	Change Case		Base Case	Change Case
Year 1	$596,730	$596,730	$36,705	$633,435	$633,435
Year 2	$587,358	$587,358	$81,334	$668,693	$668,693
Year 3	$577,259	$577,259	$129,211	$706,470	$706,470
Year 4	$570,930	$570,930	$171,414	$742,344	$742,344
Year 5	$561,698	$561,698	$214,035	$775,733	$775,733
Year 6	$554,072	$555,221	$257,254	$811,326	$812,475
Year 7	$545,552	$546,725	$298,818	$844,370	$845,542
Year 8	$534,445	$536,204	$346,425	$880,870	$882,628
Year 9	$524,805	$527,149	$389,475	$914,280	$916,625
Year 10	$514,847	$517,466	$430,939	$945,786	$948,405
Year 11	$505,945	$507,834	$471,173	$977,118	$979,007
Year 12	$495,700	$497,589	$517,560	$1,013,260	$1,015,149
Year 13	$485,660	$487,549	$557,243	$1,042,902	$1,044,791

Exhibit 6-9 provides the annual GridFlorida-wide revenue requirements for both existing and new facilities and the combined annual revenue requirements under the existing tariff and the proposed GridFlorida tariff. The difference between the

[69] Transactions that do not sink within the GridFlorida footprint will bear a through-and-out charge, rather than a zonal charge. The Through-and-out rate is based on the load-weighted average of the transmission owners' zonal rates.

total Base Case and Change Case revenues represents the loss of pancaked transmission revenues after Year 5.

<u>Phasing in the costs of Transmission Dependent Utilities (TDUs):</u> Seminole and FMPA are TDUs that have loads and resources embedded in FPL and PEF's service areas. Currently, transmission providers are not required to pay for facilities of TDUs unless those facilities are integrated into the transmission provider's system. TDUs have two options to have the costs of their existing facilities included in GridFlorida rates. One option is a phase-in of all TDU facilities at 20% per year such that 100% of the TDU facilities are included in GridFlorida Zonal rates beginning in year 5. The second option provides for the immediate inclusion in zonal rates for those facilities, and only those facilities, that are determined to be integrated by FERC. The option must be selected at the time the TDU joins GridFlorida and cannot be changed. The implication of each of these choices is described below. In either case, a TDU adder is included in the zonal charges for transactions that sink in FPL or PEF's zone to recover the costs of TDU facilities that are to be included in GridFlorida rates as determined by the option selected. PEF and FPL bear additional costs for TDU facilities and TDUs receive the benefit of reduced costs.

In years six through ten, the TDU facilities that have been included in zonal rates, either through phase-in or through FERC determination of integration, are moved out of the zonal rate and into the system rate at 20% per year such that in year ten, TDU facility costs, along with all other transmission facility costs, are born by all GridFlorida customers.

Exhibit 6-10 provides the annual TDU revenue requirements for both existing and new facilities. Existing facilities are split between the zones that they are to be phased into: east (FPL) and west (Progress).

Exhibit 6-10 TDU Revenue Requirements
(Thousands 2004$)

Year	Existing Facilities				New Facilities	
	FMPA East	Seminole East	FMPA West	Seminole West	FMPA	Seminole
Year 1	$23,520	14,016	$6,860	7,938	1,758	1,629
Year 2	$23,050	13,640	$6,723	7,779	7,928	4,163
Year 3	$22,589	11,471	$6,588	7,624	9,140	6,697
Year 4	$22,137	11,109	$6,457	7,471	10,416	8,869
Year 5	$21,694	10,755	$6,327	7,322	17,382	10,824
Year 6	$21,260	10,408	$6,201	7,175	17,962	12,236
Year 7	$20,835	10,068	$6,077	7,032	20,315	13,231
Year 8	$20,418	9,735	$5,955	6,891	27,559	13,756
Year 9	$20,010	9,408	$5,836	6,753	28,606	14,480
Year 10	$19,610	9,088	$5,720	6,618	29,058	15,114
Year 11	$19,218	8,774	$5,605	6,486	29,058	15,494
Year 12	$18,833	8,467	$5,493	6,356	35,936	16,055
Year 13	$18,457	8,165	$5,383	6,229	35,936	16,616

<u>Phasing out Long-term Pancake Rate Charges</u>

Pancaking of transmission charges occurs when a transmission customer bears more than one transmission charge within Peninsular Florida for a single transaction. The GridFlorida tariff provides that long-term firm point-to-point transmission charges be "de-pancaked" over years six through ten[70]. All charges except the charge for the zone where the transaction sinks are reduced by 20% per year starting in year six and are eliminated in year ten. Pancaked charges for transactions that involve more than one transmission customer will not be "de-

[70] Short-term point-to-point transmission charges are de-pancaked on day one of GridFlorida operations.

pancaked" unless the load where the transaction sinks receives the benefit of the reduced transmission charges.

Exhibit 6-11 shows the expected "pancaked" transmission revenues under the Base Case and under the proposed GridFlorida Tariff (Change Case). As described above the GridFlorida Tariff filed with the FPSC phases out "pancaked" transmission revenues over a 10-year period.

Exhibit 6-11
Projected "Pancaked" Transmission Revenues under the Existing Tariff (Base Case) and Under the GridFlorida RTO Tariff (Change Case)
(Thousands 2004$)

"Pancaked" Revenues		
Year	**Base Case**	**Change Case**
Year 1	$30,202	$30,202
Year 2	$27,036	$27,036
Year 3	$24,847	$24,847
Year 4	$19,134	$19,134
Year 5	$16,565	$16,565
Year 6	$12,625	$11,476
Year 7	$9,811	$8,639
Year 8	$9,811	$8,053
Year 9	$8,566	$6,222
Year 10	$7,857	$5,238
Year 11	$6,305	$4,416
Year 12	$6,305	$4,416
Year 13	$6,305	$4,416
NPV (Years 1-13)[71]	**$164,763**	**$153,551**

The pancaked revenues under the GridFlorida tariff extends through Year 10 to Year 13 in Exhibit 6-11 represent those transactions that are not de-pancaked as described above.

[71] Using a real discount rate of 3.15%

The costs shifts described below were estimated in accordance with the pricing structure of the GridFlorida RTO tariff. For purposes of modeling the transmission owner cost shifts, a comparison is made of the amount of revenue requirements the transmission owner's native load must bear before and after implementation of GridFlorida. Pre-GridFlorida, we assume that the Transmission owner's native load revenue requirement responsibility is its zonal load ratio share of the transmission owner's revenue requirement (reduced for pancaked transmission revenue). Currently, a Transmission Owner's native load is not required to bear costs for transmission facilities that the Transmission Owner does not use. They also receive the benefit of pancaked transmission revenues. Post-GridFlorida, under the phase-in plans described above, native load bears revenue requirement responsibility for all transmission facilities in GridFlorida, including TDU facilities, and experiences increased revenue requirements as pancaked revenues are eliminated.

For example, FPL revenue requirement (reduced for pancaked transmission revenues) under current rates is allocated to network customers based on its zonal load ratio share - 90.61% to FPL native load; 6.04% to Seminole load in FPL territory and 3.35% to FMPA load in FPL territory. Similarly the total revenue requirement for PEF under current rates is allocated by zonal load ratio share - 79.4% to PEF native load; 14.36% to Seminole load in PEF's territory and 6.23% to FMPA's load in PEF's territory. Under GridFlorida RTO operation in Years 1 through 9, the revenue requirements of each utility will be recovered based on a combination of zonal and GridFlorida-wide system load ratio share.

Exhibit 6-12 shows the Year 1 load-ratio-share by utility zone used to allocate each utility's base case transmission revenue requirements and the change case existing transmission revenue requirements, and the Year 1 GridFlorida load ratio share that would be used to allocate each utility's transmission revenue requirement for new facilities under the GridFlorida tariff. The zonal load ratio share and the GridFlorida load ratio share vary on a year-by-year basis based on each utility's peak demand growth.

Exhibit 6-12
Year 1 Zonal and GridFlorida-wide Load Ratio Share (LRS)

Year 2004	Zonal LRS	System-wide LRS
FPL	90.61%	45.97%
FMPA – East (FPL)	3.35%	1.70%
SECI - East (FPL)	6.04%	3.06%
FMPA – West (PEF)	6.23%	1.63%
SECI - West (PEF)	14.36%	3.76%
Progress	79.40%	20.77%
OUC	100%	2.71%
TECO	100%	9.93%
Gainesville	100%	1.04%
JEA	100%	6.24%
Lakeland	100%	1.40%
Tallahassee	100%	1.35%
RCID	100%	0.43%

Exhibit 6-13 shows the revenue requirements for existing and new facilities by utility for Year 1.

Exhibit 6-13
Year 1 Revenue Requirements
(Thousands 2004$)

Year 1 (2004)	Existing Facilities	New Facilities
FPL	$299,392	$ 18,179
FMPA - East (FPL)	$23,520	$ 1,035
SECI - East (FPL)	$14,016	$ 1,303
FMPA - West (PEF)	$6,860	$ 723
SECI - West (PEF)	$7,938	$ 326
Progress	$131,362	$ 9,367
OUC	$15,151	$ 1,040
TECO	$37,664	$ 2,170
Gainesville	$4,530	$ 66
JEA	$29,422	$ 1,562
Lakeland	$16,756	$ 53
Tallahassee	$6,983	$ 48
RCID	$3,136	$ 832

<u>Total Costs Shifts:</u> The total cost shifts are estimated by comparing the transmission companies' native load's load ratio share of transmission costs pre-GridFlorida RTO to the load ratio share of costs post GridFlorida RTO.

Exhibit 6-14 shows the Year 1 cost shifts for each utility's native load pre and post the GridFlorida RTO and the relevant summary for jurisdictional and non-jurisdictional utilities. Overall the jurisdictional consumers incur a cost shift of $11,217,000 and the non-jurisdictional consumers earn that as a benefit.

Exhibit 6-14
Year 1 Transmission Owner Cost Shifts
(Thousands 2004$)

	Native Load Revenue Requirement Allocation		
Utility	**Base Case**	**Change Case**	**Shifts**
FPL	287,746	294,951	7,205
Progress	111,742	114,280	2,538
FMPA-East (FPL)	35,207	29,735	(5,472)
FMPA-West (PEF)	16,355	14,459	(1,896)
FMPA-Total	51,562	44,194	(7,368)
SECI-East (FPL)	34,492	30,865	(3,626)
SECI-West (PEF)	28,479	27,025	(1,454)
SECI – Total	62,971	57,890	(5,080)
OUC	16,191	16,147	(44)
TECO	39,834	41,308	1,474
Gainesville	4,596	4,910	314
JEA	30,984	31,713	729
Lakeland	16,809	17,271	462
Tallahassee	7,032	7,478	446
RCID	3,968	3,292	(676)
TOTAL (Peninsular Florida)	633,435	633,434	(1)
Jurisdictional Consumers	439,322	450,539	11,217
Non-Jurisdictional Consumers	194,113	182,895	(11,218)

Thus in Year 1, the jurisdictional consumers subsidize the non-jurisdictional consumers by $11 million (2004$) in transmission costs. Over the 13-year forecast period and in net present value terms, the jurisdictional consumers subsidize the non-jurisdictional consumers by approximately $525 million in transmission payments. See Exhibit 6-15.

Exhibit 6-15
Annual Jurisdictional and Non-Jurisdictional Cost Shifts
(Thousands 2004$)

Year	Jurisdictional costs	Non-Jurisdictional Benefits
Year 1	$ 11,217	$ 11,217
Year 2	$ 26,108	$ 26,108
Year 3	$ 35,655	$ 35,655
Year 4	$ 46,279	$ 46,279
Year 5	$ 60,223	$ 60,223
Year 6	$ 59,788	$ 58,640
Year 7	$ 59,723	$ 58,551
Year 8	$ 63,178	$ 61,419
Year 9	$ 62,001	$ 59,656
Year 10	$ 59,913	$ 57,294
Year 11	$ 56,901	$ 55,012
Year 12	$ 59,937	$ 58,048
Year 13	$ 57,807	$ 55,918
NPV (Years 1-13) [72]	$ 531,454	$ 520,337

[1] Using a real discount rate of 3.15%

Data and Assumptions

Data to calculate the cost shifting estimates were provided by the participating transmission owners. Other assumptions were developed by the Project Steering Committee. Year 1 existing facilities revenue requirements were assumed to be equal to the transmission revenue requirements at December 31, 2003. Future years' existing facility revenue requirements were reduced by 2% per year to approximate the net effect of retirements, depreciation and increased O&M on revenue requirements. Revenue requirements for new facilities were estimated by applying a fixed carrying charge rate to accumulated gross plant in service. No revenue requirements were provided by FMPA, Homestead, New Smyrna Beach or Reedy Creek. In consultation with FMPA, the revenue requirements that were provided in the 2002 GridFlorida pricing

[72] Using a real discount rate of 3.15%

team study[73] were used. FMPA's carrying charge rate was assumed to be equal to Seminole's. Reedy Creek's revenue requirements provided in the 1999 study were used and Reedy Creek carrying charge rate was assumed to be equal to OUC's rate. Homestead and New Smyrna Beach were not included for cost shift estimation due to lack of data. The Investor Owned Utilities' (IOUs') carrying charge rate was assumed to be the same as was used in the prior studies, 17%. Pancaked revenues were not available for the non-jurisdictional utilities, except JEA.

[73] The GridFlorida stakeholders previously have prepared studies to evaluate the impact of cost shifts. The first study was performed in 2000 utilizing 1999 data which was updated in 2002 for the ISO compliance filing at the FPSC.

CHAPTER SEVEN
CONCLUSIONS

This study examined the costs and benefits to Peninsular Florida consumers of transforming the current decentralized market to a centrally organized market under two modes of operation – a Day-1 only RTO and a Delayed Day-2 RTO. A Day-1 Only RTO configuration reflects 13 years of decentralized company operation, but with a single transmission provider under a single GridFlorida-wide transmission tariff. A Delayed Day-2 RTO configuration comprises three initial years of Day-1 operation, followed by 10 years of Day-2 operation. Under Day-2 operation, unit commitment and dispatch for the entire Peninsular Florida region is centralized under the GridFlorida RTO, and all market participants take transmission service from the RTO under a single tariff. Each of these two RTO modes of operation is compared to a Base Case that reflects the decentralized market as-is, with individual company and control area operation, multiple transmission providers and "pancaked" transmission rates.

The primary costs and benefits of market transformation (such as envisioned under GridFlorida) come from four principal sources: 1) operational efficiency, 2) investment efficiency, 3) efficiencies in market participant operations, and 4) the net cost of forming and maintaining a new RTO. In this study, only selected aspects of operational efficiencies were explicitly quantified. Potential efficiencies from investments and those aspects of operational efficiencies that were not explicitly quantified were treated qualitatively. The change in market participant operational costs in working with the new RTO was not included in the scope of this study.

The quantitative results of this study alone do not provide the net costs and benefits to Peninsular Florida consumers of an RTO except when considered together with the qualitative factors and the change in costs associated with changes in existing utility operational costs as a result of forming the RTO. All the quantitative results in this chapter are in year 2004 net present value (NPV) dollars. Also, the results are determined before accounting for qualitative costs and benefits, and before any benefits or costs associated with the change in each market participant's operation as a direct result of the formation of the RTO.

For this assessment, the costs and benefits to Peninsular Florida has been forecast over a 13-year planning period, which in calendar years may be referred to as 2004 through 2016, but which can be more appropriately thought of as Year 1 through Year 13. The quantitative benefits to Peninsular Florida consumers of Day-1 Only RTO operation is $71 million over this period, but the quantitative start-up and operating costs of a "greenfield" Day-1 RTO with wholly new physical facilities, systems and personnel is $775 million. Thus, the Day-1 RTO configuration reflects a net quantitative loss of $704 million. The quantitative benefits under a Delayed Day-2 RTO case are much higher at $968 million. However, the start-up and operating costs of a "greenfield" Delayed Day-2 RTO with all new facilities is $1.25 billion. Hence the Delayed Day-2 RTO also reflects a net loss of $285 million. Exhibit 7-1 summarizes these findings along with the results of the sensitivity cases described in the following paragraphs.

The quantitative benefits of the Day-1 RTO and Delayed Day-2 RTO indicate that the majority of the benefits to Peninsular Florida consumers come from centralized market operation, especially from centralized unit commitment. The model calibration exercise revealed through the realized hurdle rates that the inefficiencies associated with unit commitment are by far larger than those associated with dispatch. This outcome is not surprising because in Peninsular Florida, more than ten entities separately commit units to meet load for a system with a total peak load of approximately 43 GW[74]. Contrast this with systems such as PJM (116 GW); NYISO (31 GW) and ISO-NE (25 GW) where a single entity performs unit commitment. Secondary benefits arise from centralized dispatch, but the inefficiencies associated with dispatch are not nearly as large as those associated with unit commitment, as there is already a high level of connectivity between control areas in Florida and most transactions occur between adjacent systems. The need for transactions wheeled through multiple systems in Florida is typically limited in both frequency and size. Thus, the benefits of eliminating "pancaked" transmission charges may not be as significant in Peninsular Florida as in other US power markets. Additionally, most transmission service provided in Florida is Network Service, as opposed to Point-to-Point Service, and utilities pay for transmission based on their respective load ratio share of the embedded cost of the transmission system, giving them Network Customer priority. As such, their transactions are not subject to additional wheeling charges. For these reasons, maintaining a decentralized unit commitment and dispatch operation under a Day-1 RTO configuration, similar to the existing market, is expected to yield only moderate benefits.

[74] The three jurisdictional utilities comprise almost 77% of the load and the incremental benefit of centralized unit commitment may not be as large as the incremental benefit of unit commitment for the eight non-jurisdictional utilities that perform centralized unit commitment.

Qualitative Factors. There are also various qualitative factors that should be considered along with the quantitative costs and benefits estimated for the Day-1 and Delayed Day-2 RTO operations. The qualitative factors that are expected to provide benefits in both Day-1 and Day-2 RTO configurations are:

- Investment efficiencies due to the availability of price signals from centralized markets;
- Long term bilateral transactions that may be enabled because of the elimination of pancaked transmission charges and other inefficiencies associated with transmission scheduling in decentralized markets, such as the elimination of transmission scheduling by Contract Path;
- Market transparency enabled by spot markets with posted prices;
- Ease of participation by power marketers and merchant generation;
- Potential for higher rates of return, increased efficiency and high operational standards.

On the qualitative cost side, the introduction of the RTO could introduce transition risks as the market moves from a decentralized operation to a centralized operation, and the RTO's scope in terms of organizational and regulatory requirements could also expand beyond what has been anticipated in this study.

Sensitivity Analyses. Two sensitivities were performed as a part of this study.

- A first sensitivity analysis performed was the case of Jacksonville Electric Authority (JEA) and Tallahassee (TALL) as non-participants in the GridFlorida RTO (referred to as the "JEA and TALL Out Case"). This case assumed the possibility that JEA and TALL could decline to be participants of a GridFlorida RTO due to their close proximity to Georgia and their previous involvement with the now suspended SeTrans RTO. The likelihood of JEA and TALL out of a GridFlorida RTO would result in a smaller GridFlorida RTO in terms of geographic footprint and peak demand.

- The second sensitivity analysis assumed that in comparison to the simulation model used for the analysis, a Day-2 market would still have some inherent inefficiencies associated with demand uncertainty and the fact that transactions would have some minimum sizes as would transaction margins. For example, in the simulation model used for this analysis, demand is known with perfect certainty therefore unit commitment tends to be more precise than would be achievable in actual practice. Similarly, minimum transaction sizes and/or transaction margins are often smaller in the model than in actual practice and that tends to increase trade volumes. Exhibit 7-1 shows results of both the Reference Case and sensitivity analyses. All the sensitivity analyses yielded lower quantitative benefits than in the Reference Case.

Exhibit 7-1
Summary of Quantitative RTO Costs and Benefits (Million 2004$)
NPV (Years 1-13)[75]

Case	RTO Operation	RTO Benefits	RTO Costs[1]	Net Benefit/Costs[2]
Reference Cases	Day-1 Only	71	775	-704
	Delayed Day-2	968	1,253	-285
JEA and TALL Out Case	Delayed Day-2	891	1,253	-362
Market Imperfection Case	Delayed Day-2	810	1,253	-443

[1]Discounted using a 3.15 percent real discount rate
[2]The RTO Costs presented are only costs associated with the new RTO entity. Changes in existing utility operational costs have not been considered in this estimate

The quantitative RTO benefits of a smaller GridFlorida RTO with JEA and TALL as non-participants are $891 million. The JEA and TALL loads together are approximately 7.5% of the total GridFlorida RTO load, and the benefits reflect a reduction of approximately 8% when compared to the Delayed Day-2 RTO quantitative benefits in the Reference case. The costs of the "greenfield" RTO would remain unchanged, therefore the net quantitative loss to Peninsular Florida consumers with JEA and TALL as non-participants of GridFlorida is $362 million.

In the market imperfection sensitivity analysis case, the quantitative Delayed Day-2 RTO benefits were as low as $810 million and with the RTO costs unchanged, the loss to Peninsular Florida consumers would be as high as $443 million.

[75] Discounted using a 3.15 percent real discount rate

7.1 Jurisdictional and Non-Jurisdictional RTO Costs/Benefits and Transmission Owner Cost Shifts

The quantitative RTO costs and benefits in the Reference Case were disaggregated between consumers of the utilities that are jurisdictional and those that are non-jurisdictional to the FPSC. The benefits to each of these two groups were estimated from the change in their local generation and bilateral transactions between the two groups and external imports. The non-jurisdictional utilities receive $82 million, which represents approximately 116% of the Day-1 RTO benefits. The non-jurisdictional utilities incur a loss of 16% of the Day-1 RTO benefits, i.e., $11 million. Although these benefits/losses are not that large compared to the Delayed Day-2 RTO case, the elimination of "pancaked" transmission charges seems to favor the non-jurisdictional utilities. The jurisdictional utilities import a very small amount of power from the non-jurisdictional utilities especially in the early years even after taking the Seminole and FMPA loads out of the FPL and PEF territories.

Exhibit 7-2
Summary of Jurisdictional and Non-jurisdictional Consumer Day-1 and Delayed Day-2 RTO Costs and Benefits (2004 Million$)

NPV (Years 1-13)	Day-1 Only Operation			Delayed Day-2 Operation		
	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit
RTO Benefits	-11	82	71	411	557	968
RTO Costs	599	176	775	969	284	1,253
Net Benefits	-610	-93	-704	-558	274	-285

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate.

Similarly, jurisdictional utilities receive 42%, i.e., $411 million of the Delayed Day-2 RTO benefits and the non-jurisdictional consumers receive 58%, i.e., $557 million. The non-jurisdictional consumers receive the bulk of the benefits under a Delayed Day-2 RTO operation because the Day-2 benefits of centralized unit dispatch for the eight non-jurisdictional entities are larger than the benefits for the three jurisdictional entities.

The quantitative RTO costs were also disaggregated between the two groups based on load ratio share i.e. 77% for the jurisdictional consumers and 23% for the non-jurisdictional consumers. Using these ratios, in the Day-1 RTO case, the jurisdictional consumers would incur a cost of $599 million and the non-jurisdictional consumers would incur a cost of $176 million. In the Delayed Day-2 RTO case, the jurisdictional consumers would incur a cost of $969 million, and the non-jurisdictional consumers would incur a cost of $284 million.

Combined in the Day-1 RTO case, the jurisdictional consumers would incur a loss of $610 million and the non-jurisdiction consumers would incur a loss of $93 million. In the Day-2 RTO case, the jurisdictional consumers would incur a loss of $558 million, but the non-jurisdictional consumers would earn a benefit of $274 million.

When the transmission facilities of all Peninsular Florida utilities are blended in under the proposed GridFlorida tariff filed by the GridFlorida Applicants in March 2003, significant transmission owner cost shifts would arise. Jurisdictional transmission owners incur a cost shift of approximately $525 million from the non-jurisdictional transmission owners i.e., the jurisdictional consumers subsidize the non-jurisdictional consumers by $525 million in transmission payments. Exhibit 7-3 shows the combined effect of transmission owner cost shifts and jurisdictional and non-jurisdictional benefits and costs. While the overall GridFlorida consumer cost/benefit remain unchanged, the inclusion of the transmission owner cost shifts exacerbates the quantitative loss to jurisdictional consumers and improves the benefits to non-jurisdictional consumers.

Exhibit 7-3
Summary of Jurisdictional and Non-jurisdictional Consumer Day-1 and Delayed Day-2 RTO Costs and Benefits (2004 Million$)

NPV (Years 1-13)	Day-1 Only Operation			Delayed Day-2 Operation		
	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit
RTO Benefits	-11	82	71	411	557	968
RTO Costs	599	176	775	969	284	1,253
Transmission Owner Costs[76] (Cost Shifts)	525	-525	-	525	-525	-
Net Benefits	-1,135	431	-704	-1,083	798	-285

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate.

7.2 Summary of Conclusions

ICF's analysis shows that the quantitative benefits of a Delayed Day-2 RTO operation are significant, and range from $810 million to $968 million in the scenarios in this study. However, the cost of a "greenfield" Delayed Day-2 RTO with wholly new systems, physical facilities and personnel, designed along FERC's Standard Market Design principles, is also very significant at $1.25 billion. The prospects of a Day-1 RTO are bleak, especially if designed along a "greenfield" RTO with wholly new systems, personnel and physical facilities, because the benefits of a Day-1 RTO operation are not nearly as large as a Delayed Day-2 RTO operation, while the fixed costs are high.

[76] The Transmission Owner costs shifts have been estimated based on the GridFlorida tariff filed with the FPSC by the GridFlorida Applicants. However the quantitative RTO benefits have been estimated using a simplified form of the tariff structure because the tariff as filed did not lend itself to analytic modeling. Thus, the net benefits shown in Exhibit 7-3 should be interpreted as indicative rather than definitive.

The overall outcome of net benefits or costs to Peninsular Florida consumers depends on both quantitative and qualitative aspects of the RTO. If the net benefits from the qualitative factors should be within the range of $285 million and $443 million then the GridFlorida Delayed Day-2 RTO could breakeven under the scenarios examined in this study.

This study also indicates that the non-jurisdictional consumers would receive net positive benefits of $798 million from the implementation of a GridFlorida Delayed Day-2 RTO while jurisdictional consumers would receive a net loss of $1.1 billion. While the overall GridFlorida consumer cost/benefit remains unchanged, the RTO cost allocation and the transmission owner cost shifts exacerbates the quantitative loss to jurisdictional consumers and improves the benefits to non-jurisdictional consumers.

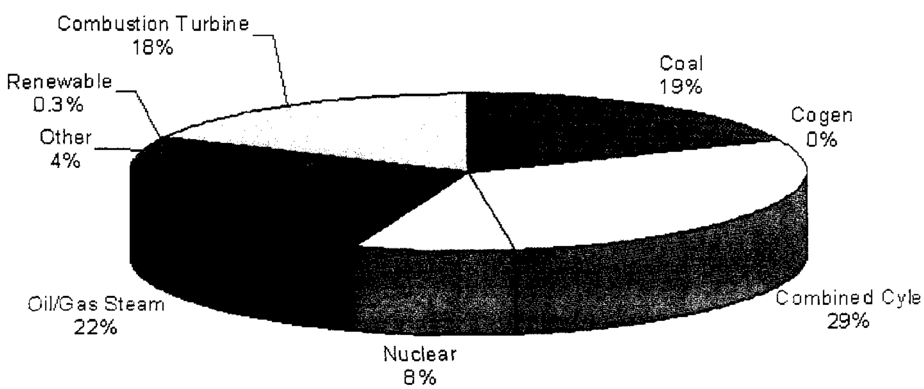
APPENDIX A
ASSUMPTIONS

Exhibit A-1
FRCC 2004 Peak Demand and Net Energy for Load

	2004 Summer Peak Demand and Growth through 2016	2004 Net Energy for Load and Growth through 2016
2004 Forecast	42,999	226,267
2005	2.5%	2.5%
2006	2.5%	2.5%
2007	2.5%	2.5%
2008	2.2%	2.2%
2009	2.3%	2.3%
2010	2.4%	2.4%
2011	2.3%	2.3%
2012	2.3%	2.3%
2013	2.3%	2.3%
2014	2.3%	2.3%
2015	2.3%	2.3%
2016	2.2%	2.2%
Simple Average 2004 - 2016	2.3%	2.3%

Note: **Annual peak demand and expected growth rates were provided directly by the Applicants and Stakeholders**

Exhibit A-2
FRCC Installed Capacity by Type – 2003 (GW)



Total Capacity – 50.6 GW

Note: Data above includes dedicated generation facilities outside physical FRCC boundaries

Exhibit A-3
Key Environmental Assumptions

Parameter	Treatment
SO_2 Regulations	Phase II Acid Rain -- no tightening of current legislation assumed
NO_X Regulations	NO_X OTR[77]; SIP[78] Call[79]
CO_2 Regulations	None
Mercury Regulations	None
Allowance Prices (2003$/ton)	SO2
2004	188
2005	201
2006	215
2007	230
2008	245
2009	261
2010	288
2012	311
2014	337
2016	349

Source: ICF

Exhibit A-4
Henry Hub Forecast

Year	Reference Case	
	2003 $/MMBtu	Nominal [80]$/MMBtu
2004	5.73	5.86
2005	5.24	5.48
2006	4.70	5.03
2007	4.17	4.56
2008	4.27	4.77
2009	3.71	4.24
2010	3.60	4.21
2011	3.71	4.43
2012	3.83	4.68
2013	4.07	5.08
2014	3.98	5.08
2015	3.64	4.75
2016	3.80	5.07

Source: ICF

[77] Ozone Transport Region
[78] State Implementation Plan
[79] The SIP Call does not affect the state of Florida
[80] Assumes an inflation rate of 2.25%

Exhibit A-5
Florida Delivered Gas Price Forecast (2003 $/MMBtu)

Year	Henry Hub	Basis Differential	Delivered
2004	5.73	0.39	6.12
2005	5.24	0.39	5.63
2006	4.70	0.39	5.09
2007	4.17	0.39	4.56
2008	4.27	0.39	4.66
2009	3.71	0.39	4.10
2010	3.60	0.39	3.99
2011	3.71	0.39	4.10
2012	3.83	0.39	4.22
2013	4.07	0.39	4.46
2014	3.98	0.39	4.37
2015	3.64	0.39	4.03
2016	3.80	0.39	4.19

Source: ICF

Note: The above table reflects average regional delivered spot natural gas prices including basis differentials and LDC charges. LDCs are assumed average $0.07/MMBtu regionally. Newly constructed plants are not expected to pay any LDCs, however will incur by-pass or connection charges.
Source: ICF

Exhibit A-6
Florida Delivered Oil Price Forecast (2003 $/MMBtu)

Year	Distillate Oil	1% Sulfur Residual Oil
2004	6.71	5.23
2005	5.67	4.33
2006	5.62	4.31
2007	5.52	4.25
2008	5.64	4.40
2009	5.55	4.34
2010	5.40	4.22
2011	5.49	4.28
2012	5.58	4.34
2013	5.68	4.41
2014	5.79	4.47
2015	5.89	4.53
2016	5.96	4.59

Source: ICF

Note:
Oil product prices were determined using ICF estimates of refinery margins and productivity changes over time
Transportation differentials are used to reflect delivered prices to facilities operating in the GridFlorida territory

APPENDIX B
CALIBRATION RESULTS

Exhibit B-1
2003 Peninsula Florida Generation* and Imports (GWh) – Reported 2003 Historical versus Network Resource Case Calibration

Control Area (A)	Reported Historical 2003 Generation (GWh) (B)	ICF Model Calibration (GWh) (C)	Deviation of Model Calibration from Historical (GWh) (D)=C-B	% Deviation of Model Calibration from Historical (E)={(D)/B*100}
Total Dispatch for Peninsular Florida *	185,235	186,549	1,314	1%
Imports from Southern **	21,529	20,853	-676	-3%

Source: GridFlorida Applicants and Stakeholder
The total reported capacity and generation is the sum of the 2003 unit capacity and dispatch reported by Florida Power & Light, Progress Energy Florida, Tampa Electric Company, Seminole Electric Cooperative and member systems, Gainesville Regional Utilities, Jacksonville Electric Authority, Florida Municipal Power Agency (FMPA) member systems, Orlando Utilities Commission, Lakeland Electric, City of Tallahassee Electric Department. Excludes resources of New Smyrna Beach, Reedy Creek Improvement District and City of Homestead

Exhibit B-2

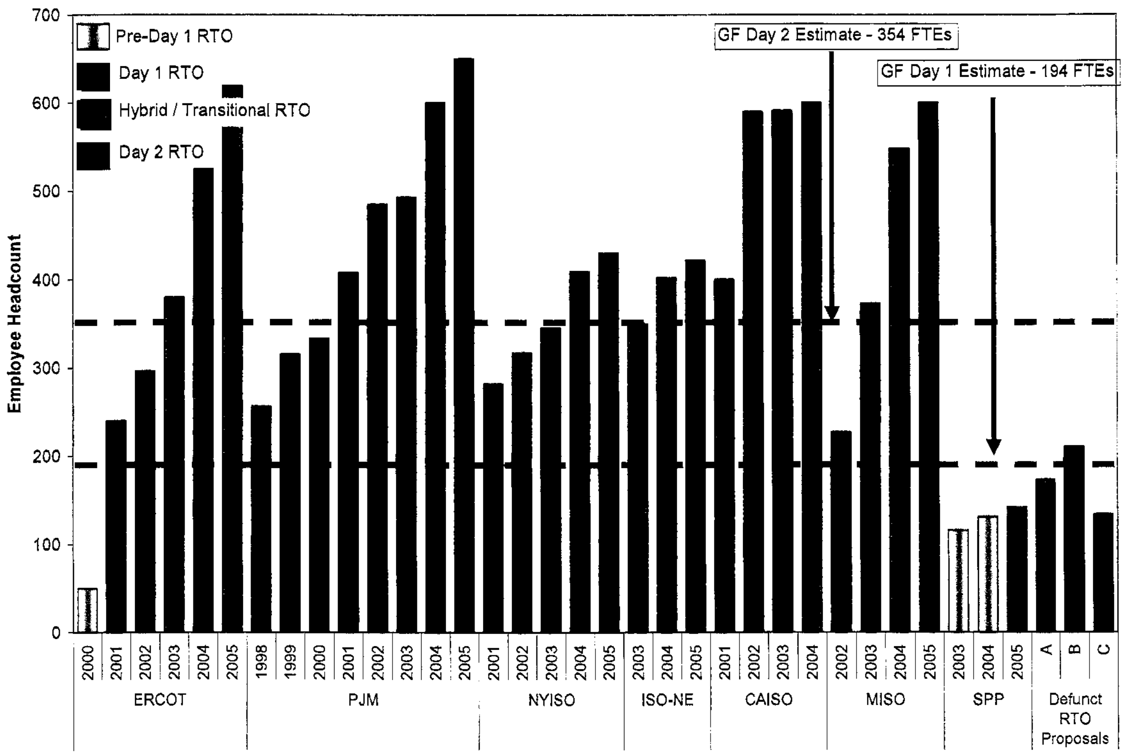
2003 Generation* (GWh) by Control Area – Reported 2003 Historical versus Network Resource Case Calibration

Control Area (A)	Reported Historical 2003 Generation (GWh) (B)	ICF Model Calibration (GWh) (C)	Deviation of Model Calibration from Historical (GWh) (D)=C-B	% Deviation of Model Calibration from Historical (E)=((D)/B*100)
FP&L	89,859	88,452	-1,407	-2%
Progress	36,334	36,640	306	1%
TECO	15,775	15,537	-238	-2%
Seminole	12,349	11,830	-519	-4%
City of Tallahassee	2,375	2,881	506	21%
Jacksonville	12,323	12,460	137	1%
Gainesville	1,809	1,668	-141	-8%
FMPP	14,409	17,082	2,673	19%

*Source: GridFlorida Applicant and Stakeholder Data Submissions

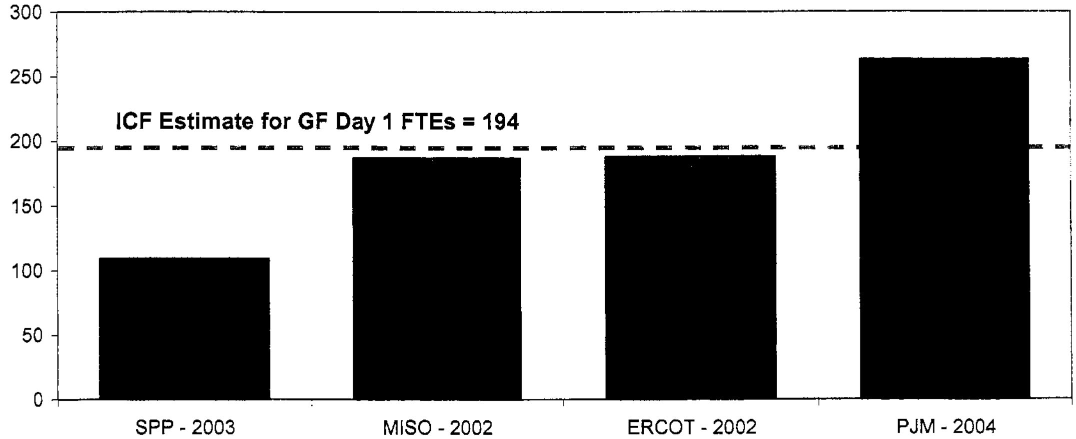
APPENDIX C
SELECT BENCHMARKING RESULTS

Exhibit C-1
Comparison of Grid Florida RTO and Existing ISO/ RTO Employee Counts



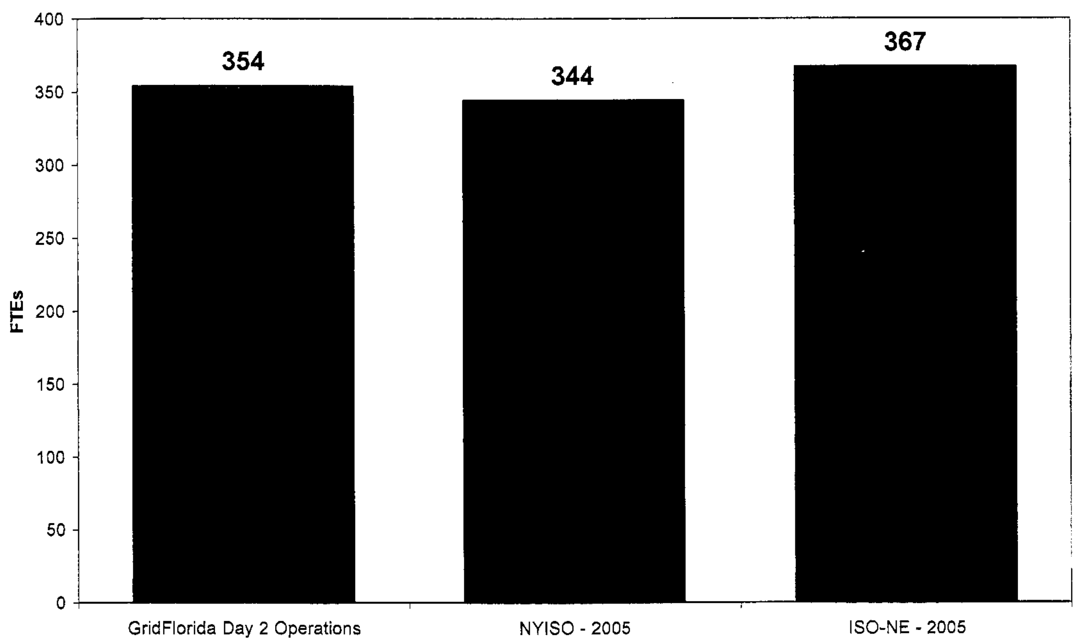
Source: RTO contacts, annual reports, budget proceedings and other publicly available sources.

Exhibit C-2
GridFlorida FTE Estimates vs. FERC Estimates of Day 1 Staff Needs



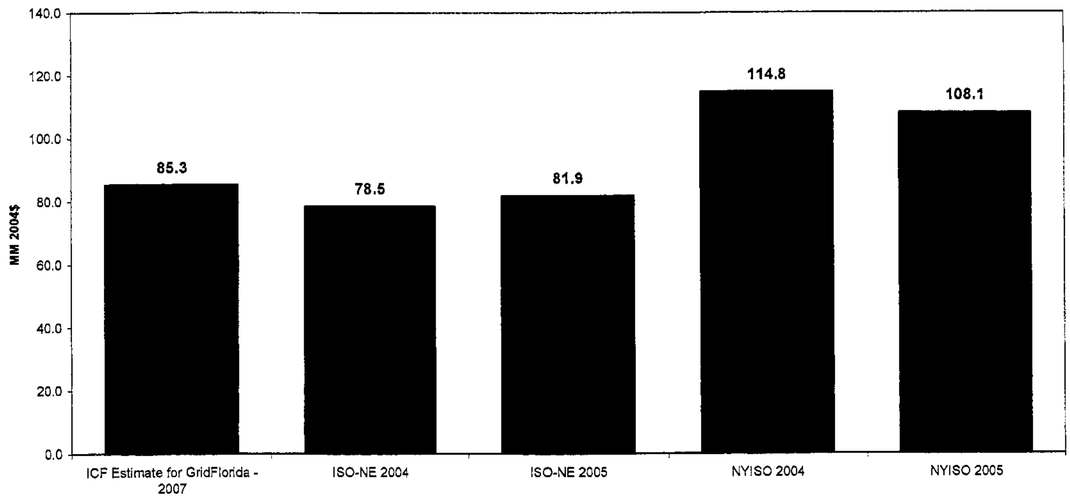
Source: ICF Consulting, "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization" Docket No. PL04-16-000, October 2004

Exhibit C-3
Comparable Day 2 FTE Count for GridFlorida, ISO-NE, and NYISO



Note: ISO-NE and NYISO FTE counts adjusted to match specified GridFlorida RTO functions.
Source: ICF worked directly with ISO-NE and NYISO to develop the FTE comparability estimates

Exhibit C-4
Comparison of GridFlorida Day 2 Operating Costs with Existing ISOs

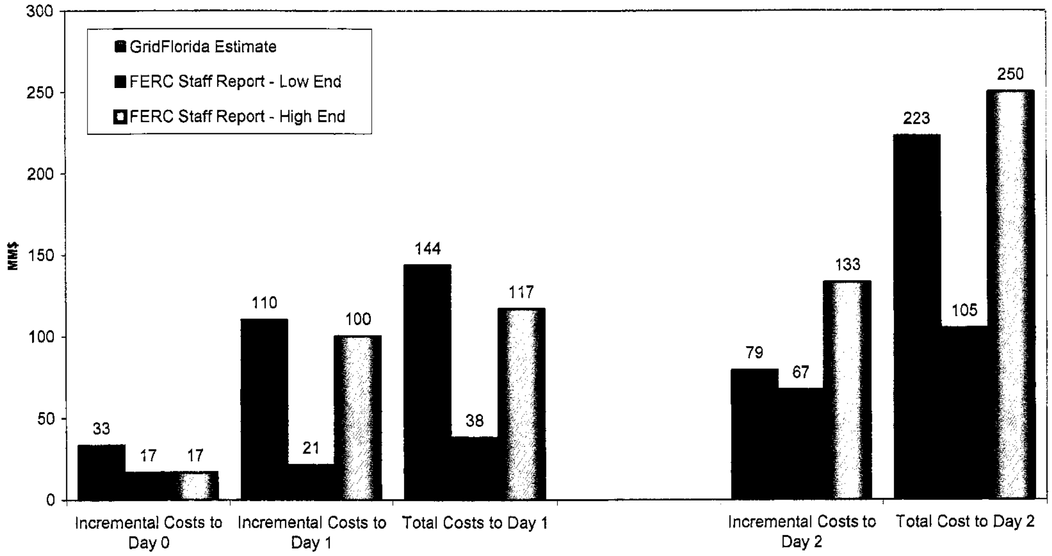


Notes:
All estimates exclude debt service, capital expenses, blackout related expenses (NYISO 2004), and FERC fees.
GridFlorida 2004 total demand – 226 TWh; NYISO 2004 total demand – 160 TWh; ISO-NE 2004 total demand – 131 TWh
GridFlorida 2004 peak demand – 43.0; NYISO 2004 peak demand – 28.4 GW; ISO-NE 2004 peak demand – 23.7 GW

Sources:
GridFlorida – ICF Consulting 4.20.2005
ISO-NE 2004 - http://www.iso-ne.com/committees/budget_and_finance/2004/2004-09-02/2005%20Budget%20Materials%20for%20BF%209-2-04.pdf
ISO-NE 2005 - http://www.iso-ne.com/committees/budget_and_finance/2004/2004-05-13/March%20Forecast%20for%20year%20end%202004.pdf

NYISO 2004 -
http://www.nyiso.com/services/documents/groups/mc_budgets_stdrds_perf_sub/09_26_03/ver2_092603_bsp_presentation.pdf
NYISO 2005 - mdex.nyiso.com/publish/Document/49bd70_ffbd1dd2ea_-7f650a03015f?rev=1&action=download&_property=Attachment

Exhibit C-5
ICF Start-up Costs Estimates vs. the FERC Staff Report



Source: ICF Consulting, "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization" Docket No. PL04-16-000, October 2004

APPENDIX D
RTO COST MODEL DETAIL

Final

Estimate of GridFlorida Capital and Annual Operating Costs for Day 1 and Day 2 Operations

Prepared by: ICF Consulting

Prepared for: GridFlorida Applicants and Stakeholders

August 30, 2005

Kojo Ofori-Atta
kofori-atta@icfconsulting.com

Chris McCarthy
chrismccarthy@icfconsulting.com

ICF CONSULTING

Line #	GridFlorida Startup Cost Detail - Day 0 (2004$) - Draft Final Item	Cost 000$	% of Total	Notes
5				
6	Costs Incurred Through 12/31/2003	18,969	57%	Source: GridFlorida Applicants
7	Estimated Incremental costs to Day 0 (provided by GridFlorida Applicants)	14,400	43%	Source: GridFlorida Applicants
8	**Total Costs to Day 0**	**33,369**		
		19.0		

GridFlorida Startup Cost Detail - Day 1 (2004$) - Draft Final

Line #	Item	Cost 000$	% of Total	Notes
5				
6	**Facilities**			
7	**HQ**			
8	Interim office space (25,000 sq. ft 9 months)	640	1%	Source: ICF regional survey
9	Pre-operation HQ occupancy (9 months)	1,647	1%	Source: ICF regional survey
10	Facility hardening ($35 per sf)	3,511	3%	Source: ICF
11	Leasehold improvements (control center upgrades and furnishings)	200	0%	Source: ICF
12	Facility design support	176	0%	Source: ICF regional survey
13	Secure access system	86	0%	Source: ICF
14	IT network infrastructure	291	0%	Source: ICF
15	Telecom infrastructure	352	0%	Source: ICF
16	Office furniture	1,371	1%	Source: Vendor quotes
17	Backup generator and UPS (includes installation and contingency)	2,600	2%	Source: Vendor quotes
18	**Backup Control Center/Disaster Recovery Facility (BCC)**			
19	Backup generator and UPS (includes installation and contingency)	1,000	1%	Source: Vendor quotes
20	Office furniture	78	0%	Source: Vendor quotes
21	Pre-operation BCC occupancy (6 months)	284	0%	Source: ICF
22	**Facility Subtotal**	12,237	11%	
23				
24	**Corporate Inception**			
25	Executive staff and board recruiting (industry standard 33 percent of annual salary)	1,474	1%	Source: ICF
26	Non-executive staff recruiting ($1,500 average per FTE)	267	0%	Source: ICF
27	Relocation expense (FRCC industry standard)	5,648	5%	ICF regional survey
28	External legal fees (includes corporate inception, market rules development support, regulatory filings, etc...)	8,000	7%	Source: ICF
29	Consultant fees (systems procurement, contract management, and organizational design)	1,000	1%	Source: ICF
30	Travel and business expenses during inception	207	0%	Source: ICF
31	External financial and operational audits	200	0%	Source: ICF
32	**Corporate Inception Subtotal**	16,796	15%	
33				
34	**Systems**			
35	IT network and architecture design consultant	1,000	1%	Source: ICF
36	Energy Management System (EMS) - (includes hardware, software licenses, SCADA, powerflow model, training, scheduling and tagging needs, user terminals, and contingency analysis software; HQ and backup sites included)	14,000	13%	Source: Vendor quotes
37	EMS simulation and training system (hardware and software licenses)	3,000	3%	Source: Vendor quotes
38	EMS customization contingency	3,000	3%	Source: ICF estimate
39	Independent control zone communication and frame relay initiation	900	1%	Source: Vendor quotes
40	Market monitor inception (outsourced)	500	0%	Source: Vendor quotes
41	OASIS inception (includes customer portal)	2,000	2%	Source: Vendor quotes
42	Map board	1,868	2%	Source: Vendor quotes
43	Transmission models (GE MAPS, PSSE, etc)	645	1%	Source: GridFlorida Applicants
44	Commercial Operations / Billing and Settlement systems (includes HW/SW for: data acquisition, billing and settlement, customer relations, database licenses, systems integration, 3 environments, system rollout, and contingency)	6,500	6%	Source: ICF
45	**System Subtotal**	33,413	30%	
46				
47	**Operating Costs Prior to Day 1**			
48	Salary, benefits, and payroll taxes during inception (assumes max of 18 months in place preceding Day 1 operations)	33,887	31%	Note: average 14 month employment for 194 FTEs preceding Day 1
49	Board of directors expense during inception (in place 18 months preceding operation)	1,470	1%	Source: FERC Form 1
50	Executive signing bonus (15 percent)	583	1%	Source: ICF industry survey
51	Non-executive signing bonus (5 percent)	629	1%	Source: ICF industry survey
52	Insurance during inception (18 months)	1,892	2%	Source: FERC Form 1
53	PC Lease during inception (average 12 months)	267	0%	Source: ICF industry survey
54	Repro services during inception (12 months)	351	0%	Source: ICF
55	Telecom during inception (average 12 months)	488	0%	Source: ICF industry survey
56	Payroll administration (18 months)	203	0%	industry standard 1% of salary expense
57	Benefit administration (18 months)	406	0%	industry standard 2% of salary expense
58	**Operating Costs to Day 1**	40,175	36%	
59				
60	Subtotal - ICF Day 1 Startup Costs	102,622	93%	
61	Day 0 Costs Interest during construction for 18 month ramp-up period @ 4.2 percent	2,162	2%	Source: ICF
62	Day 1 Costs Interest during construction for 18 month ramp-up period @ 4.2 percent	5,427	5%	Source: ICF
63	Contingency	-	0%	
64	**Total ICF Day 1 Estimate (including IDC)**	**110,210**	100%	
65				
66	Estimated costs to Day 0	33,369		Source: GridFlorida Applicants
67	**Total Costs to Day 1**	**143,579**		

Line #	Item	Cost 000$	% of Total	Notes/Source
5				
6	**Facilities**			
7	**HQ**			
8	Facility hardening ($35 per sf)	1,552	2%	
9	Facility design support	76	0%	Source: ICF regional survey
10	IT network infrastructure	240	0%	Source: ICF
11	Telecom infrastructure	290	0%	Source: ICF
12	Office furniture	1,016	1%	Source: Vendor quotes
13	**Facility Subtotal**	3,174	4%	
14				
15	**Corporate Inception**			
16	External legal fees	-	0%	Note: assumes all Day 2 needs are met in house
17	Executive staff recruiting (industry standard 33 percent of annual salary)	1,139	1%	Source: ICF
18	Non-executive staff recruiting ($1,500 average per FTE)	215	0%	Source: ICF
19	Relocation expense (FRCC industry standard)	2,400	3%	ICF regional survey
20	Consultant Fees (market design, organizational design)	1,000	1%	Source: ICF
21	Travel and business expenses	189	0%	Source: ICF
22	External financial and operational audits	200	0%	Source: ICF
23	Systems procurement, and contract management	1,531	2%	Source: ICF
24	**Corporate Inception Subtotal**	6,673	8%	
25				
26	**Systems**			
27	Real-time market system (HW/SW)	4,000	5%	Source: Vendor quotes
28	Day ahead market system (HW/SW)	5,000	6%	Source: Vendor quotes
29	FTR market system (HW/SW)	6,000	8%	Source: Vendor quotes
30	Commercial operations / Billing and Settlement systems (includes incremental HW / SW upgrades, customer relationship system upgrades, incremental market participant portals, integration with market systems, and contingency)	4,500	6%	Source: Vendor quotes
31	Off-site data warehouse	7,425	9%	Source: Vendor quotes
32	Market monitor expansion (outsourced)	1,500	2%	Source: Vendor quotes
33	BCC market systems (DA, RT, FTR)	5,850	7%	Source: Vendor quotes
34	Market simulation and training system (DA, RT, FTR)	4,000	5%	Source: Vendor quotes
35	**Systems Subtotal**	38,275	48%	
36				
37	**Operating Costs Prior to Day 2**			
38	Executive signing bonus (15 percent)	450	1%	Source: ICF
39	Non-executive signing bonus (5 percent)	539	1%	Source: ICF
40	Salary, benefits, and payroll taxes during inception (assumes max of 18 months in place preceding day 2 operations)	25,069	32%	Note: average 15 month employment for incremental FTEs preceding Day 2
41	Insurance during inception (18 months)	-	0%	Source: FERC Form 1
42	PC Lease during inception (average 12 months)	187	0%	Source: ICF industry survey
43	Repro services during inception	193	0%	Source: ICF
44	Telecom during inception (average 12 months)	342	0%	Source: ICF industry survey
45	Payroll administration (18 months)	90	0%	Industry standard 1% of salary expense
46	Benefit administration (18 months)	300	0%	Industry standard 2% of salary expense
47	**Operating Costs Prior to Day 2**	27,169	34%	
48				
49	Subtotal - ICF Day 2 Estimate without IDC	75,292	95%	
50	Interest during construction for 18 month ramp-up period @ 4.2 percent	3,981	5%	Source: ICF
51	Contingency	-	0%	NA
52	**Total ICF Day 2 Estimate (including IDC)**	**79,273**	100%	
53				
54	Estimated costs to Day 0	33,369		Source: GridFlorida applicants
55	Estimated costs to Day 1	110,210		Source: ICF
56	**Total Costs to Day 2**	**222,851**		

ICF

GridFlorida Annual Operating Cost Detail - Day 1 Only ($000)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2004 % of Total	Notes
Facilities															
HQ															
Headquarters lease	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	4%	Approx. 97,000 sq ft @ 22.8 per year
Utilities	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	2%	Electric, water, sewer
Corporate telecom	471	471	471	471	471	471	471	471	471	471	471	471	471	1%	Non-EMS and control center costs; include long distance, equipment, etc...
Backup control center															
Utilities	218	218	218	218	218	218	218	218	218	218	218	218	218	0%	Electric, water, sewer
Backup control center lease	569	569	569	569	569	569	569	569	569	569	569	569	569	1%	25,000 sq ft @ 22.8 per year
Facilities Subtotal	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**7%**	
Staffing															
Board of Directors expense	990	999	1,009	1,020	1,030	1,040	1,050	1,061	1,072	1,082	1,093	1,104	1,115	2%	Non salary expense (travel, meetings, etc...); Source: FERC Form 1
Salary, benefits and payroll tax expense by division (assumes 1% annual real salary escalation)															
Office of the President	946	956	965	975	985	994	1,004	1,014	1,025	1,035	1,045	1,056	1,066	2%	6 FTEs
Control Center Ops	6,883	6,951	7,021	7,091	7,162	7,234	7,306	7,379	7,453	7,527	7,603	7,679	7,755	11%	51 FTEs
EMS IT Support	2,090	2,111	2,132	2,154	2,175	2,197	2,219	2,241	2,264	2,286	2,309	2,332	2,355	3%	14 FTEs
Planning and Engineering	3,481	3,516	3,551	3,587	3,623	3,659	3,695	3,732	3,770	3,807	3,845	3,884	3,923	6%	25 FTEs
Member Services	1,974	1,994	2,013	2,034	2,054	2,074	2,095	2,116	2,137	2,159	2,180	2,202	2,224	3%	14 FTEs
Legal and Regulatory	2,030	2,050	2,070	2,091	2,112	2,133	2,154	2,176	2,198	2,220	2,242	2,264	2,287	3%	11 FTEs
Corporate Services	3,364	3,398	3,432	3,466	3,501	3,536	3,571	3,607	3,643	3,679	3,716	3,753	3,791	5%	26 FTEs
Corporate IT Support	1,950	1,970	1,989	2,009	2,029	2,050	2,070	2,091	2,112	2,133	2,154	2,176	2,197	3%	13 FTEs
Committee and Working Group Support	427	431	436	440	444	449	453	458	462	467	472	476	481	1%	3 FTEs
Security	2,112	2,133	2,155	2,176	2,198	2,220	2,242	2,265	2,287	2,310	2,333	2,357	2,380	3%	17 FTEs
Commercial Operations	845	854	862	871	880	888	897	906	915	924	934	943	952	1%	5 FTEs
Market Monitor	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	NA
Billing and Settlement	1,327	1,340	1,353	1,367	1,381	1,394	1,408	1,422	1,437	1,451	1,466	1,480	1,495	2%	9 FTEs
Mature Market Functions	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	NA
Annual performance bonus (15% average)	2,463	2,488	2,513	2,538	2,563	2,589	2,615	2,641	2,667	2,694	2,721	2,748	2,775	4%	
Total Salary and Benefit Cost	**30,882**	**31,191**	**31,503**	**31,818**	**32,136**	**32,457**	**32,782**	**33,109**	**33,441**	**33,775**	**34,113**	**34,454**	**34,798**	**50%**	**194 total FTEs**
Systems															
ICCP expense	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	5%	Source: ICF
Billing and settlement system maintenance and license	192	192	192	192	192	192	192	192	192	192	192	192	192	0%	Vendor quote
EMS maintenance, license, and 24-hr support	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	3%	Vendor quote
OASIS maintenance and license fees	200	200	200	200	200	200	200	200	200	200	200	200	200	0%	Vendor quote
Transmission models (GE MAPS, PSSE, OPF, etc) maintenance and license fees	118	118	118	118	118	118	118	118	118	118	118	118	118	0%	
Systems Subtotal	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**9%**	
Outsourced Functions															
Market monitor	500	505	510	515	520	526	531	536	541	547	552	558	563	1%	Vendor quote
Training (EMS OASIS, billing and settlement, etc...)	626	632	638	645	651	658	664	671	678	685	691	698	705	1%	Source: ICF; includes system operations, dispatch, etc...
Payroll administration	185	187	189	190	192	194	196	198	200	202	204	206	208	0%	Industry standard 1% of salary expense
Benefit administration	370	373	377	381	385	389	392	396	400	404	408	413	417	1%	Industry standard 2% of salary expense
Annual external audit	150	150	150	150	150	150	150	150	150	150	150	150	150	0%	Source: ICF
Accounting and tax compliance	700	707	714	721	728	736	743	750	758	766	773	781	789	1%	Source: ICF
Repro services	351	355	358	362	365	369	373	377	380	384	388	392	396	1%	Source: ICF
Branding, marketing, and PR Expenses	103	103	103	103	103	103	103	103	103	103	103	103	103	0%	Source: ICF
Outsourced Subtotal	**2,985**	**3,012**	**3,040**	**3,068**	**3,096**	**3,124**	**3,153**	**3,182**	**3,211**	**3,241**	**3,271**	**3,301**	**3,332**	**5%**	
Other/Misc															
Insurance	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	2%	Source: FERC Form 1
Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	NA - assumed not-for-profit
Travel and business expenses	138	138	138	138	138	138	138	138	138	138	138	138	138	0%	Source: ICF
Community relations	308	311	314	317	321	324	327	330	334	337	340	344	347	0%	Source: ICF
Relocation expenses	310	314	317	320	323	326	330	333	336	340	343	346	350	1%	Assumes 4.8 percent turnover annually; Source: Dynamics of Economic Well-Being: Labor Force Turnover, 1996-1999, Bureau of Census
PC lease	238	238	238	238	238	238	238	238	238	238	238	238	238	0%	$93/month; 10 percent contingency
IT Other	489	489	489	489	489	489	489	489	489	489	489	489	489	1%	Includes network maintenance, ISP, remote access, email, software licenses, and training
Miscellaneous	652	652	652	652	652	652	652	652	652	652	652	652	652	1%	Office supplies, consumables, postage etc...; Source: ICF
Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	
Incremental FERC Fees	2,259	2,316	2,385	2,442	2,495	2,551	2,614	2,674	2,736	2,798	2,862	2,925	2,991	4%	
Other/Misc Subtotal	**5,656**	**5,719**	**5,795**	**5,858**	**5,918**	**5,980**	**6,049**	**6,116**	**6,184**	**6,253**	**6,324**	**6,394**	**6,466**	**9%**	
Subtotal - ICF Day 1 Operating Costs	**49,576**	**49,975**	**50,389**	**50,796**	**51,202**	**51,614**	**52,036**	**52,460**	**52,888**	**53,322**	**53,760**	**54,201**	**54,649**	**80%**	
Capital and Interest Expenses															
Interest expense on capitalized Day 0 and Day 1 startup costs	7,849	6,442	4,957	3,392	1,741	-	-	-	-	-	-	-	-	13%	Assumes 5 year payoff of startup costs. 100% debt @ 5.5% interest
Recapitalization of Day 1 investment	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	7%	
Interest expense on recapitalization	232	423	570	670	722	722	722	722	722	722	722	722	722	0%	
Capital and Interest Expenses Subtotal	**12,330**	**11,114**	**9,776**	**8,311**	**6,712**	**4,971**	**4,971**	**4,971**	**4,971**	**4,971**	**4,971**	**4,971**	**4,971**	**20%**	
Total Day 1 Annual Cash Expenses	**61,906**	**61,089**	**60,166**	**59,107**	**57,914**	**56,585**	**57,007**	**57,431**	**57,859**	**58,293**	**58,730**	**59,172**	**59,620**	**100%**	**Note, excludes depreciation**
2004-2016 NPV of Day 1 Operating Costs @ 3.15 % real discount	**640,308**														

GridFlorida Annual Operating Cost Detail - Day Two Incremental ($000) - Real 2004$

GridFlorida Annual Operating Cost Detail - Day 2 Incremental ($000)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2007 % of Total	Notes
Facilities															
HQ															
Headquarters lease	-	-	-	956	956	956	956	956	956	956	956	956	956	2%	Incremental 42,000 sq ft @ 22.8 per year
Incremental utilities	-	-	-	435	435	435	435	435	435	435	435	435	435	1%	Electric, water, sewer
Corporate telecom	-	-	-	412	412	412	412	412	412	412	412	412	412	1%	Non-EMS and control center costs; include long distance, equipment, etc...
Facilities Subtotal	-	-	-	1,803	1,803	1,803	1,803	1,803	1,803	1,803	1,803	1,803	1,803	4%	
Incremental Staffing															
Board of Directors Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	na
Salary, benefits and payroll tax expense by division (assumes 1% annual real salary escalation from 2002)															
Office of the President	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	na
Control Center Ops	-	-	-	5,024	5,074	5,125	5,176	5,228	5,280	5,333	5,386	5,440	5,495	10%	35 incremental FTEs
EMS IT Support	-	-	-	2,530	2,555	2,581	2,606	2,632	2,659	2,685	2,712	2,739	2,767	5%	18 incremental FTEs
Planning and Engineering	-	-	-	3,321	3,354	3,388	3,421	3,456	3,490	3,525	3,560	3,596	3,632	7%	24 incremental FTEs
Member Services	-	-	-	2,105	2,126	2,147	2,169	2,190	2,212	2,234	2,257	2,279	2,302	4%	12 incremental FTEs
Legal and Regulatory	-	-	-	601	607	613	619	625	631	638	644	651	657	1%	3 incremental FTEs
Corporate Services	-	-	-	653	659	666	673	679	686	693	700	707	714	1%	4 incremental FTEs
Corporate IT Support	-	-	-	1,219	1,231	1,244	1,256	1,268	1,281	1,294	1,307	1,320	1,333	2%	10 incremental FTEs
Committee and Working Group Support	-	-	-	129	130	132	133	134	136	137	139	140	141	0%	1 incremental FTEs
Security	-	-	-	222	224	226	229	231	233	236	238	240	243	0%	2 incremental FTEs
Commercial Operations	-	-	-	4,302	4,345	4,388	4,432	4,476	4,521	4,566	4,612	4,658	4,705	9%	25 incremental FTEs
Market Monitor	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	na
Billing and Settlement	-	-	-	2,000	2,020	2,040	2,061	2,081	2,102	2,123	2,144	2,166	2,187	4%	12 incremental FTEs
Market Design and Mature Market Functions (ramps up	-	-	-	-	1,211	2,445	2,470	2,495	2,519	2,545	2,570	2,596	2,622	0%	14 incremental FTEs
Annual performance bonus (15% average)	-	-	-	1,985	2,114	2,245	2,267	2,290	2,313	2,336	2,359	2,383	2,407	4%	
Total Salary and Benefit Cost	-	-	-	24,090	25,650	27,239	27,511	27,786	28,064	28,345	28,628	28,915	29,204	48%	160 incremental FTEs
Systems															
ICCP expense	-	-	-	668	668	668	668	668	668	668	668	668	668	1%	Source: ICF
Billing and settlement system maintenance	-	-	-	608	608	608	608	608	608	608	608	608	608	1%	Vendor quote
OASIS maintenance and license fees	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	vendor quote
Real-time market system maintenance	-	-	-	500	500	500	500	500	500	500	500	500	500	1%	Vendor quote
Day-ahead market system maintenance	-	-	-	600	600	600	600	600	600	600	600	600	600	1%	Vendor quote
FTR market system maintenance	-	-	-	300	300	300	300	300	300	300	300	300	300	1%	Vendor quote
Off-site data warehouse maintenance	-	-	-	400	400	400	400	400	400	400	400	400	400	1%	Source: ICF
Systems Subtotal	-	-	-	3,076	3,076	3,076	3,076	3,076	3,076	3,076	3,076	3,076	3,076	6%	
Outsourced Functions															
Market monitor	-	-	-	1,545	1,608	1,624	1,641	1,657	1,674	1,690	1,707	1,724	1,741	3%	Vendor quote
Training (market systems, billing and settlement)	-	-	-	968	977	987	997	1,007	1,017	1,027	1,038	1,048	1,058	2%	Source: ICF; includes market system training
Payroll administration	-	-	-	144	154	163	165	166	168	170	171	173	175	0%	Industry standard 1% of salary expense
Benefit administration	-	-	-	288	307	326	329	333	336	339	343	346	350	1%	Industry standard 2% of salary expense
Annual external audit	-	-	-	150	150	150	150	150	150	150	150	150	150	0%	Source: ICF
Accounting and tax compliance	-	-	-	577	583	589	595	601	607	613	619	625	631	1%	Source: ICF
Credit analysis	-	-	-	682	689	696	703	710	717	724	731	739	746	1%	Source: ICF
Repro services	-	-	-	193	195	197	199	201	203	205	207	209	211	0%	
Branding, marketing, and PR expenses	-	-	-	103	103	103	103	103	103	103	103	103	103	0%	Source: ICF
Outsourced Subtotal	-	-	-	4,652	4,767	4,836	4,882	4,928	4,975	5,022	5,070	5,118	5,167	9%	
Other/Misc															
Insurance	-	-	-	1,472	1,472	1,472	1,472	1,472	1,472	1,472	1,472	1,472	1,472	3%	Source: FERC Form 1
Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	na - assumed not-for-profit
Travel and business expenses	-	-	-	126	126	126	126	126	126	126	126	126	126	0%	
Community relations	-	-	-	451	456	460	465	469	474	479	484	488	493	1%	
Relocation expenses	-	-	-	96	97	98	99	100	101	102	103	104	105	0%	Assumes 4.8 percent turnover annually; Source: Dynamics of Economic Well-Being: Labor Force Turnover, 1996-1999, Bureau of Census
PC lease	-	-	-	196	196	196	196	196	196	196	196	196	196	0%	Source: ICF
IT Other	-	-	-	403	403	403	403	403	403	403	403	403	403	1%	Includes network maintenance, ISP, remote access, email, software
Miscellaneous	-	-	-	538	538	538	538	538	538	538	538	538	538	1%	Office supplies, consumables, postage etc...; Source: ICF
Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	
Incremental FERC Fees				3,479	3,556	3,635	3,725	3,811	3,898	3,987	4,078	4,168	4,262	7%	
Other/Misc Subtotal	-	-	-	6,762	6,844	6,929	7,024	7,116	7,209	7,304	7,400	7,496	7,596	14%	
Incremental Day 2 Annual Operating Costs	-	-	-	40,383	42,139	43,883	44,296	44,709	45,127	45,550	45,977	46,407	46,845	81%	
Capital and Interest Expenses															
Interest expense on capitalized Day 2 startup costs	-	-	-	4,334	3,557	2,737	1,873	961	-	-	-	-	-	9%	Assumes 5 year payoff of startup costs. 100% debt @ 5.5% interest
Recapitalization of Day 2 investment	-	-	-	4,999	4,999	4,999	4,999	4,999	4,999	4,999	4,999	4,999	4,999	10%	
Interest expense on recapitalization	-	-	-	273	493	656	760	801	776	750	722	692	661	1%	
Capital and Interest Expenses Subtotal	-	-	-	9,606	9,049	8,393	7,632	6,762	5,775	5,749	5,721	5,691	5,660	19%	
Incremental Day 2 Annual Operating Costs	-	-	-	49,989	51,188	52,275	51,928	51,471	50,902	51,298	51,698	52,099	52,505	100%	Note, excludes depreciation
2004-2016 NPV of Incremental Day 2 Operating Costs @ 3.15 % real discou	409,848														

Appendix E
Disaggregated RTO Benefits

Summary of Disaggregated Benefits (Day-1)

Disaggregated Benefits	2004	2005	2006	2007	2008	2009	2010	2011*	2012	2013*	2014	2015*	2016
Jurisdictional Consumers [1] (000 Nominal $)	16,583	1,448	1,769	4,684	1,513	-550	-5,446	-5,761	-6,077	-4,757	-3,437	-12,785	-22,133
Non Jurisdictional Consumers [2] (000 Nominal $)	849	3,680	3,573	3,887	4,334	7,957	9,827	9,623	9,419	10,225	11,031	21,868	32,704
Total Peninsular Florida Benefits (000 Nominal $)	17,432	5,128	5,342	8,571	5,847	7,407	4,381	3,861	3,342	5,468	7,595	9,083	10,571
% Allocation													
Jurisdictional Consumers	95%	28%	33%	55%	26%	-7%	-124%	-149%	-182%	-87%	-45%	-141%	-209%
Non Jurisdiction Consumers	5%	72%	67%	45%	74%	107%	224%	249%	282%	187%	145%	241%	309%
Projected Jurisdictional Load (GWhs)	175,012	179,473	184,898	189,209	193,609	197,852	202,654	207,227	211,799	216,557	221,315	226,178	231,041
Projected Non Jurisdictional Load (GWhs)	51,255	52,496	53,973	55,359	56,316	57,683	59,165	60,680	62,195	63,751	65,307	66,911	68,514
	23%	77%											
Jurisdictional Consumer Benefit per unit (cents/kWh)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
Non Jurisdictional Consumer Benefit per unit (cents/kWh)	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.03	0.05
Peninsular Florida Benefit per unit (cents/kWh)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Day 1 Costs (000 Nominal $)	87,649	90,224	92,841	95,472	98,120	63,243	65,149	67,110	69,132	71,217	73,366	75,581	77,866
Allocation of Delayed Day 2 RTO Cost [3]													
Jurisdictional Consumers	67,794	69,806	71,864	73,861	76,011	48,967	50,427	51,910	53,439	55,020	56,650	58,326	60,057
Non Jurisdiction Consumers	19,855	20,418	20,978	21,611	22,109	14,276	14,722	15,200	15,693	16,197	16,717	17,255	17,809
Net Day 1 Benefits (000 Nominal $)													
Jurisdictional Consumers	-51,212	-68,358	-70,094	-69,177	-74,498	-49,517	-55,873	-57,671	-59,516	-59,776	-60,086	-71,111	-82,190
Non Jurisdiction Consumers	-19,006	-16,738	-17,405	-17,723	-17,776	-6,320	-4,896	-5,578	-6,274	-5,972	-5,685	4,613	14,895
Net Day 1 Benefits (000 2004 $)													
Jurisdictional Consumers	-51,212	-66,854	-67,043	-64,710	-68,154	-44,304	-48,890	-49,353	-49,811	-48,928	-48,100	-55,672	-62,930
Non Jurisdiction Consumers	-19,006	-16,370	-16,647	-16,579	-16,262	-5,654	-4,284	-4,773	-5,251	-4,888	-4,551	3,612	11,404

Net Present Value - Delayed Day1 Benefits (000 2004 $)	
Jurisdictional Consumers	**($610,554)**
Non Jurisdiction Consumers	**($92,936)**

Notes:

[1] The Jurisdictional consumers are the customers of Florida Power and Light, Progress Energy and Tampa Electric

[2] The Non-Jurisdiction consumers include customers of Seminole Electrc, Jacksonville Electric, Tallahassee, FMPA, Reedycreek, City of Homestead, OUC, Lakeland Electric, Gainsville Electric, New Smyrna Beach

[3] Based on Load Ratio share

* Interpolated

All Benefits are in Nominal Dollars

Summary of Disaggregated Benefits (Delayed Day-2)

Disaggregated Benefits	2004	2005	2006	2007	2008	2009	2010	2011*	2012	2013*	2014	2015*	2016
Jurisdictional Consumers [1] (000 Nominal $)	16,583	1,448	1,769	56,478	54,099	36,528	40,882	46,573	52,263	64,771	77,279	81,410	85,542
Non Jurisdictional Consumers [2] (000 Nominal $)	849	3,680	3,573	56,838	75,773	73,431	67,157	79,847	92,538	94,687	96,835	96,468	96,100
Total Peninsular Florida Benefits (000 Nominal $)	17,432	5,128	5,342	113,317	129,871	109,960	108,039	126,420	144,801	159,458	174,114	177,878	181,642
% Allocation													
Jurisdictional Consumers	95%	28%	33%	50%	42%	33%	38%	37%	36%	41%	44%	46%	47%
Non Jurisdiction Consumers	5%	72%	67%	50%	58%	67%	62%	63%	64%	59%	56%	54%	53%
Projected Jurisdictional Load (GWhs)	175,012	179,473	184,898	189,209	193,609	197,852	202,654	207,227	211,799	216,557	221,315	226,178	231,041
Projected Non Jurisdictional Load (GWhs)	51,255	52,496	53,973	55,359	56,316	57,683	59,165	60,680	62,195	63,751	65,307	66,911	68,514
	23%	77%											
Jurisdictional Consumer Benefit per unit (cents/kWh)	0.01	0.00	0.00	0.03	0.03	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04
Non Jurisdictional Consumer Benefit per unit (cents/kWh)	0.00	0.01	0.01	0.10	0.13	0.13	0.11	0.13	0.15	0.15	0.15	0.14	0.14
Peninsular Florida Benefit per unit (cents/kWh)	0.01	0.00	0.00	0.05	0.05	0.04	0.04	0.05	0.05	0.06	0.06	0.06	0.06
Delayed Day 2 RTO Costs (000 Nominal $)	87,649	90,224	92,841	164,105	170,459	139,341	143,550	147,805	129,951	133,889	137,947	142,127	146,440
Allocation of Delayed Day 2 RTO Cost [3]													
Jurisdictional Consumers	67,794	69,806	71,864	126,959	132,049	107,887	111,111	114,328	100,453	103,438	106,516	109,680	112,947
Non Jurisdiction Consumers	19,855	20,418	20,978	37,146	38,410	31,454	32,439	33,477	29,498	30,451	31,431	32,447	33,494
Net Day 2 Benefits (000 Nominal $)													
Jurisdictional Consumers	-51,212	-68,358	-70,094	-70,481	-77,950	-71,358	-70,229	-67,755	-48,190	-38,667	-29,237	-28,270	-27,405
Non Jurisdiction Consumers	-19,006	-16,738	-17,405	19,692	37,363	41,977	34,718	46,370	63,040	64,236	65,404	64,021	62,606
Net Day 2 Benefits (000 2004 $)													
Jurisdictional Consumers	-51,212	-66,854	-67,043	-65,930	-71,312	-63,845	-61,452	-57,983	-40,332	-31,650	-23,404	-22,132	-20,983
Non Jurisdiction Consumers	-19,006	-16,370	-16,647	18,420	34,182	37,558	30,379	39,682	52,761	52,579	52,356	50,122	47,936

Net Present Value - Delayed Day 2 Benefits (000 2004 $)	
Jurisdictional Consumers	**($557,230)**
Non Jurisdiction Consumers	**$273,786**

Notes:

[1] The Jurisdictional consumers are the customers of Florida Power and Light, Progress Energy and Tampa Electric

[2] The Non-Jurisdiction consumers include customers of Seminole Electrc, Jacksonville Electric, Tallahassee, FMPA, Reedycreek, City of Homestead, OUC, Lakeland Electric, Gainsville Electric, New Smyrna Beach

[3] Based on Load Ratio share

* Interpolated

All Benefits are in Nominal Dollars

Tab 10

Presentations

Residential

Month	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Competitive States												
California	17.76	17.69	17.66	12.4	17.74	18.11	18.49	18.88	18.22	13.93	17.93	18.16
Connecticut	19.85	20.68	20.84	21.15	21.63	20.94	19.76	18.78	18.98	19.95	19.76	19.03
Delaware	13.16	12.99	13.39	13.89	14.54	13.6	12.99	13	13.05	15.44	13.83	12.9
D.C.	13.05	12.78	13.25	13.48	13.72	12.85	12.3	12.48	11.72	12.93	13.08	11.88
Georgia	10.4	10.52	11.14	11.16	11.51	12.25	12.29	12.52	11.99	11.14	11	10.43
Illinois	11.44	11.94	12.56	12.8	13.29	12.25	12.06	11.94	12.53	13.03	13.14	11.95
Maine	15.28	15.24	15.41	15.65	15.84	15.9	15.87	16.12	16.26	16.26	16.21	15.63
Maryland	14.04	13.98	14.36	14.37	14.7	14.61	14.05	13.83	14.02	15.17	14.31	14
Massachusetts	19.35	19.78	19.84	20.65	19.06	18.52	18.2	18.34	19.69	18.82	19.14	18.81
Michigan	14.51	14.88	14.83	14.95	15.33	15.41	15.37	15.87	15.71	15.67	15.37	15.16
New Hampshire	18	18.37	18.46	18.67	18.54	18.13	18	18.25	18.28	18.86	19.05	18.61
New Jersey	15.5	15.49	15.58	15.52	15.4	16.05	16.16	16.22	16.14	15.26	15.26	15.29
New York	16.54	16.76	16.89	17.39	17.73	17.89	17.94	18	18.36	18.26	17.73	17.17
Ohio	12.05	12.03	12.47	12.76	13.01	12.47	12.25	12.21	12.13	12.52	12.42	12.28
Oregon	10.18	10.35	10.42	10.5	10.8	10.79	10.78	10.86	10.96	10.98	10.76	10.62
Pennsylvania	13.88	14.02	14.06	14.26	14.42	14.03	13.76	13.81	13.96	14.32	14.14	13.66
Rhode Island	18.4	18.78	19.07	19.43	18.02	18.69	17.11	18.57	20.47	18.87	18.14	18.35
Texas	10.93	11.06	11.25	11.29	11.12	10.98	10.86	10.94	11.11	11.02	11.1	10.85
Monthly Average	14.68	14.85	15.08	15.02	15.36	15.19	14.90	15.03	15.20	15.14	15.13	14.71
Regulated States	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Alabama	11.04	11.5	12.11	12.42	12.1	12.16	12.08	12.22	12.22	12.51	12.24	11.96
Alaska	19.42	19.81	20.05	20.71	20.9	21.31	21.42	21.07		20.73	20.93	20.17
Arizona	10.9	11.46	11.75	12.36	12.94	12.54	12.7	12.56	12.71	12.1	11.6	11.23
Arkansas	8.91	9.13	9.62	10.04	10.19	10.31	10.28	10.38	10.46	9.88	10.11	9.48
Colorado	11.08	11.38	11.35	11.78	11.67	12.56	12.44	12.79	12.84	12.1	12.27	11.88
Florida	11.5	11.33	11.24	11.07	10.86	11.08	11.18	11.47	11.14	10.98	11.08	10.92
Hawaii	26.92	26.77	27.35	26.93	26.88	27.5	28.04	27.45	27.84	27.54	28.48	27.69
Idaho	9.55	9.66	9.8	9.87	10.14	10.13	10.81	10.51	10.24	10.24	10.02	9.44
Indiana	10.47	10.53	11.21	11.84	11.81	11.33	11.27	11.35	12.26	12.69	12.83	11.75
Iowa	10.43	10.92	11.5	11.7	13.01	13.57	14.07	14.28	12.43	11.86	11.63	10.37
Kansas	11.88	12.57	13.17	13.45	13.79	13.3	13.06	13.17	13.05	13.25	13.29	12.23
Kentucky	9.8	9.71	10.05	10.36	10.51	10.33	10.28	10.31	10.69	11.06	11.23	10.56
Louisiana	8.5	8.46	9.13	9.17	9.28	8.96	9.06	9.43	9.74	9.52	9.38	9.37
Minnesota	11.97	12.12	12.23	12.62	13.04	12.81	13.2	13.11	13.69	13.11	13.07	11.91
Mississippi	10.44	10.32	10.91	11.01	10.88	10.64	10.21	10.31	10.1	10.58	10.96	10.61
Missouri	9.14	9.23	10.06	10.36	11.93	12.59	12.28	12.4	11.62	10.76	11.14	9.91
Montana	10.19	10.51	10.92	11.03	11.42	11.59	11.6	11.5	11.51	11.21	10.95	10.54
Nebraska	9.26	9.65	10.31	10.65	11.05	11.9	12.1	12.02	12.33	10.73	10.7	9.7
Nevada	11.42	12.2	12.28	11.89	12.09	11.4	10.72	10.83	11.17	12.04	11.79	11.25
New Mexico	11.45	11.26	11.44	11.34	11.35	12.22	12.51	13.02	12.85	12.57	11.98	12.08
North Carolina	10.41	10.77	11.66	11.72	11.41	11.13	11.19	11.36	11.31	11.63	11.11	10.2
North Dakota	8.56	9.41	9.82	10.52	11.07	11.39	11.26	11.38	11.78	10.8	10.26	9.14
Oklahoma	8.3	9.63	10.24	10.93	10.73	9.99	9.99	10.51	11.27	11.18	9.54	9.37
South Carolina	11.68	11.9	12.86	12.77	12.54	12.68	12.58	12.76	12.98	12.64	12.75	12.21
South Dakota	10.26	10.45	10.98	11.39	12.11	11.98	12.19	11.93	12.54	12.17	11.74	10.74
Tennessee	9.9	9.61	10.01	10.22	10.25	10.37	10.45	10.54	10.64	10.71	11.05	10.74
Utah	10.54	10.61	10.67	10.71	11.01	11.51	11.72	11.89	11.2	10.63	10.67	10.65
Vermont	16.62	16.89	17.11	17.52	17.79	17.57	17.29	17.27	17.58	17.82	17.88	17.26
Virginia	10.64	10.89	11.18	12	12.03	12.24	11.71	11.74	11.64	11.17	11.45	10.67
Washington	9.06	9.21	9.22	9.33	9.54	9.59	9.6	9.57	9.8	9.52	9.6	9.27
West Virginia	10.68	10.68	11	11.29	11.41	11.16	11.19	11.57	11.6	11.9	11.73	11.22
Wisconsin	13.75	14.07	14.23	14.44	14.98	14.96	14.54	14.33	14.47	14.4	14. 07	13.41
Wyoming	10.45	10.62	10.85	10.99	11.5	11.81	11.88	11.75	11.75	11.5	11.26	10.68
Monthly Average	11.37	11.61	12.01	12.26	12.49	12.56	12.57	12.63	12.42	12.47	12.34	11.78

Month	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	17-Dec
Competitive States												
California	18.44	18.68	18.87	14.08	18.29	19.39	18.85	19.16	19.33	15.7	18.71	18.48
Connecticut	19.28	19.91	20.06	20.12	20.94	20.47	20.23	20.53	21.26	21.29	20.67	19.65
Delaware	12.83	13.37	13.86	13.62	14.77	13.4	12.71	13.04	13.36	14.2	13.72	12.99
D.C.	12.37	12.83	13.04	13.09	13.54	12.59	12.23	12.62	13.08	13.44	14	13.28
Georgia	10.83	11.54	11.71	11.49	11.7	12.53	12.59	12.85	12.56	11.52	11.09	10.66
Illinois	11.28	12.21	13.76	13.2	13.71	12.95	12.07	12.83	13.09	13.12	13.67	12.38
Maine	15.95	16.02	15.92	16.05	16.18	16.17	15.96	15.96	16.01	16.05	15.72	15.25
Maryland	14.25	14.36	14.16	14.33	14.53	14.22	13.59	13.9	13.9	14.37	13.32	13.25
Massachusetts	18.38	18.77	18.58	19.48	18.58	18.56	18.73	19.66	20.83	20.45	20.44	19.61
Michigan	15.23	15.41	15.38	15.4	15.85	15.86	15.69	15.63	15.38	15.12	15.16	15.17
New Hampshire	18.43	18.87	18.93	18.97	19.55	19.3	18.98	19.17	19.64	19.87	19.87	19.4
New Jersey	15.83	15.69	15.57	15.75	16.22	15.96	16.02	15.81	15.3	14.66	15.3	15.59
New York	17.3	17.48	17.02	17.3	18.49	18.76	18.81	18.56	18.8	18.74	17.8	17
Ohio	11.55	12.15	12.35	12.52	12.51	12.67	12.59	12.87	12.95	12.81	12.71	12.04
Oregon	10.4	10.53	10.51	10.68	10.82	10.97	10.94	10.87	10.9	10.89	10.62	10.58
Pennsylvania	13.79	14.29	14.07	14.42	14.64	14.52	14.31	14.32	14.45	14.6	14.4	14.09
Rhode Island	18.91	19.77	17.96	19.57	16.89	16.65	17.19	17.81	17.92	19.55	20.5	18
Texas	10.91	11.34	11.3	11.26	11.17	11.15	11.04	10.95	11.12	11.09	11.23	11.11
Monthly Average	14.78	15.18	15.17	15.07	15.47	15.34	15.14	15.36	15.55	15.42	15.50	14.71
Regulated States	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	17-Dec
Alabama	12.09	12.9	12.81	12.71	12.73	12.79	12.53	12.71	12.97	12.66	12.48	11.87
Alaska	20.57	20.61	21.58	21.42	22.03	22.14	22.28	21.43	21.28	21.78	21.64	21.63
Arizona	11.31	11.66	11.73	12.49	13.04	12.65	12.74	12.65	12.98	12.78	12.2	12.24
Arkansas	9.17	9.8	9.84	10.4	10.49	10.73	10.67	10.68	10.79	10.17	10.34	9.68
Colorado	11.53	11.88	11.9	11.95	11.91	12.75	12.45	12.46	12.71	12.07	12.11	11.73
Florida	11.5	11.81	11.74	11.58	11.38	12.02	11.93	11.53	11.85	11.85	11.76	11.94
Hawaii	28.32	29.39	29.04	30.33	29.07	30.45	29.25	28.76	29.03	29.3	30.58	30.75
Idaho	9.26	9.66	9.92	9.77	10.19	11.42	10.58	10.56	9.99	10.26	10	10.11
Indiana	11.28	11.78	11.99	12.57	12.3	12.05	11.85	12.33	12.63	12.75	12.71	11.29
Iowa	10.79	11.16	11.65	12.19	13.11	13.92	14.59	14.43	13.32	11.77	11.73	11.49
Kansas	11.94	12.93	13.3	13.58	13.77	13.56	13.61	13.67	13.55	13.38	13.42	12.64
Kentucky	10.26	10.59	10.48	10.76	10.66	10.68	10.64	10.82	11.19	11.17	11.19	10.4
Louisiana	7.65	9.52	9.45	9.35	9.88	10.19	9.99	10.06	10.09	9.93	9.51	8.95
Minnesota	12.14	12.83	12.58	13.03	13.37	13.96	14.01	13.75	13.59	13.36	12.73	12.64
Mississippi	10.55	11.19	11.52	11.64	11.68	11.4	11.1	10.86	10.97	11.1	11.33	10.91
Missouri	9.37	9.96	10.43	10.9	11.85	13.25	13.16	13.22	11.73	11.15	10.81	9.91
Montana	10.61	10.61	10.74	10.93	11.29	11.73	11.59	11.3	11.55	11.23	10.9	10.93
Nebraska	9.28	9.96	10.52	10.69	11.25	12.06	12	12.11	12.55	10.89	10.49	10.21
Nevada	11.55	11.91	12.17	12.32	12.15	11.64	11.64	11.75	12.02	12.79	12.88	12.34
New Mexico	11.98	12.84	12.77	12.63	12.83	13.41	13.57	13.3	13.13	12.96	12.48	12.38
North Carolina	10.47	11.14	10.99	11.43	11.27	11.07	11.2	11.18	11.54	11.45	10.75	10.42
North Dakota	8.98	9.46	9.56	10.39	11.4	12.34	11.7	12.07	12.02	10.94	9.6	9.41
Oklahoma	9.08	11.01	10.53	11.83	10.74	10.53	10.29	10.72	11.06	11.01	10.76	9.41
South Carolina	12.12	12.86	12.62	13.13	12.99	13.07	12.79	13.26	13.45	11.69	12.7	12.27
South Dakota	10.33	10.68	11.13	11.67	12.26	12.57	12.48	12.53	12.87	12.43	11.6	11.24
Tennessee	10.42	10.52	10.63	10.68	10.74	10.93	10.83	10.64	10.61	10.53	10.87	10.56
Utah	10.71	10.7	10.74	10.78	11.09	11.48	11.91	11.52	10.83	10.6	10.52	10.32
Vermont	17.05	17.51	17.39	17.72	18.04	18.02	17.74	17.74	17.92	17.95	17.87	17.33
Virginia	10.58	11.07	11.45	11.5	11.88	11.91	12.41	12.18	12.03	11.79	11.47	11.1
Washington	9.24	9.27	9.28	9.44	9.69	9.95	9.86	9.87	10.15	9.84	9.73	9.63
West Virginia	11.31	11.58	11.52	11.87	12.02	11.69	11.6	11.67	11.92	11.96	11.67	11.29
Wisconsin	14	14.33	14.51	14.75	15.35	15.05	14.65	14.64	14.82	15.09	14.47	14.21
Wyoming	10.57	10.77	10.91	11.53	11.71	12.21	12.15	12.04	12.2	11.61	11.16	11.15
Monthly Average	11.70	12.24	12.35	12.67	12.85	13.14	13.02	12.98	13.01	12.73	12.56	12.19

Month	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Competitive States												
California	18.81	19.15	19.17	16.08	18.91	19.9	19.65	20.56	19.39	15.73	19.53	19.44
Connecticut	20	21.59	21.04	21.44	21.54	21.62	20.88	21.28	22.05	21.87	21.17	20.84
Delaware	11.87	12.6	12.38	12.85	13.74	13.21	12.02	12.3	12.38	13.89	12.87	12.27
D.C.	12.3	13.38	12.18	13.72	13.73	12.05	12	12.56	12.56	13.6	13.84	13.15
Georgia	10.69	10.83	11.33	11.19	11.62	12.26	12.28	12.51	12.09	10.96	10.82	9.29
Illinois	12.49	12.23	12.73	13.04	13.21	12.56	11.76	12.32	12.19	13.23	13.25	12.3
Maine	16.02	16.22	15.61	15.74	16.27	16.16	16.31	16.28	16.01	16.47	16.38	16.11
Maryland	12.95	13.43	12.97	13.37	13.33	13.92	13.46	13.06	13.29	14.19	13.11	13.24
Massachusetts	20.6	22.23	22.49	22.34	21.69	21.11	20.63	20.86	22.15	21.3	21.3	21.99
Michigan	15.26	15.62	15.55	15.67	15.93	16.07	15.98	15.49	15.4	15.42	15.12	15.1
New Hampshire	19.23	19.84	19.93	19.8	19.76	19.63	18.88	19.28	19.87	20.23	20.08	19.78
New Jersey	15.52	15.87	15.41	15.59	15.87	15.64	15.5	15.29	15.53	14.96	15.04	15.45
New York	17.74	18.19	17.53	18	18.52	19.3	19.38	19.03	19.28	19.29	18.17	17.34
Ohio	11.82	12.25	12.55	12.66	12.81	12.64	12.7	12.67	11.39	12.48	12.37	12
Oregon	10.53	10.73	10.74	10.86	11.2	11.02	11.25	11.09	11.29	11.24	10.95	10.68
Pennsylvania	13.69	13.95	13.91	14.1	14.24	14.38	13.96	13.88	13.76	14.1	13.93	13.58
Rhode Island	22.24	21.66	20.22	20.47	20.03	18.64	18.23	18.7	22.32	21.46	21.74	22.51
Texas	10.85	11.08	11.58	11.65	11.68	11.36	11.25	11.44	11.59	11.69	11.8	11.22
Monthly Average	15.15	15.60	15.41	15.48	15.78	15.64	15.34	15.48	15.70	15.67	15.64	15.35
Regulated States	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Alabama	11.59	12.29	12.65	12.79	12.49	12.41	12.28	12.41	12.47	12.42	12.14	11.62
Alaska	21.67	21.11	21.47	21.61	22.16	22.54	23.43	22.73	22.76	22.51	21.81	21.99
Arizona	12.2	12.2	12.39	13.09	13.3	13.16	12.92	12.91	12.91	13.26	12.65	12.26
Arkansas	9.36	9.8	10.47	10	9.89	9.99	9.98	9.98	10.05	9.34	9.64	9.01
Colorado	11.55	11.73	11.72	12.06	11.96	12.28	12.67	12.5	12.55	12.27	12.12	11.9
Florida	12.03	12.14	11.75	11.36	11.54	11.37	11.29	11.27	11.31	11.67	12.14	11.86
Hawaii	31.14	31.52	32.05	31.21	32.03	32.76	33.45	32.4	32.29	32.46	33.82	34.43
Idaho	10.32	10.1	9.99	10.13	10.55	10.58	10.46	10.54	10.32	10.33	9.58	9.83
Indiana	11.09	11.52	12.13	12.31	12.3	12.02	12.05	12.26	12.33	12.39	12.38	11.89
Iowa	10.93	11.65	12.05	12.24	13.28	13.81	14.47	14.57	13.23	12.82	12.15	11.08
Kansas	12.1	12.87	13.36	13.59	12.85	11.56	12.34	13.72	12.86	13.32	12.97	11.96
Kentucky	9.78	10.36	10.55	10.62	10.66	10.56	10.35	10.47	10.7	10.77	10.73	10.36
Louisiana	8.72	8.94	9.79	9.8	9.53	9.37	9.68	9.65	9.28	9.11	9.09	9.01
Minnesota	12.42	12.56	12.71	12.88	13.77	14.09	14.22	13.99	14.57	13.72	13.1	12.87
Mississippi	10.37	11.26	12.04	12.17	12.07	11.55	10.96	10.98	10.86	11.22	11.58	11.12
Missouri	9.19	9.78	10.48	10.36	12.45	13.23	13.12	12.68	10.98	10.71	10.06	9.54
Montana	10.69	10.7	10.84	11.02	11.43	11.85	11.72	11.51	11.78	11.48	11.07	10.93
Nebraska	9.29	9.61	10.25	10.55	11.43	11.31	11.89	12.08	12.28	11.23	10.6	9.81
Nevada	12.36	12.5	12.62	12.34	12.05	11.67	11.34	11.42	11.72	12.16	12.12	11.72
New Mexico	11.92	12.21	12.67	12.58	12.14	13.37	13.37	13.62	13.1	12.97	12.3	12.04
North Carolina	10.27	11.44	11.17	11.89	11.41	11.24	11.43	11.49	11.6	11.94	11.29	10.78
North Dakota	9	9.15	9.65	10.03	11.26	12.07	11.86	11.93	12.23	10.83	9.89	9.54
Oklahoma	8.79	9.85	10.85	11.05	10.09	10.72	10.32	10.8	10.85	11	9.92	9.02
South Carolina	12.49	11.04	12.97	13.21	12.85	12.91	12.96	10.23	12.37	12.43	12.36	11.77
South Dakota	10.71	10.76	10.84	11.23	12.1	12.39	12.42	12.65	12.83	12.35	11.28	11.05
Tennessee	10.02	10.33	11.15	10.81	10.87	10.79	10.68	10.83	10.59	10.7	11.06	10.72
Utah	10.36	10.41	10.44	10.52	10.79	10.63	10.94	11.04	10.62	10.32	10.03	9.97
Vermont	17.36	18.03	17.6	17.92	18.35	18.5	17.86	17.93	17.95	18.42	18.22	18.06
Virginia	10.94	11.47	11.71	11.85	12.28	12.4	12.33	12.34	12.08	11.9	11.65	11.01
Washington	9.51	9.54	9.65	9.74	9.7	9.79	9.74	9.8	9.9	9.68	9.46	9.35
West Virginia	11.05	11.38	11.43	11.47	11.78	11.57	11.42	11.39	11.24	11.27	11.24	10.41
Wisconsin	14.01	14.29	14.41	14.69	15.21	14.28	14.28	14.36	14.88	14.94	14.29	14.06
Wyoming	10.83	10.86	11.05	11.29	11.99	12.3	12.01	11.82	12.23	11.08	11.05	10.84
Monthly Average	11.94	12.22	12.57	12.68	12.93	13.00	13.04	12.98	12.96	12.82	12.54	12.18

Commercial

Month	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Competitive States																																				
California	13.72	13.81	13.84	13.76	14.61	16.05	16.94	17.01	16.72	15.78	14.29	13.82	13.99	14.45	14.51	13.94	14.96	17.32	17.68	17.64	18.08	16.9	15.14	14.39	14.34	14.83	14.83	14.81	15.6	17.81	18.71	19.17	17.59	17.28	15.98	15.34
Connecticut	15.39	16.16	16.11	15.72	15.86	16.01	15.53	15.37	15.63	15.95	15.9	15.35	15.63	15.95	16.03	15.81	16.13	16.03	16.35	16.02	16.32	16.73	16.04	15.77	16.99	17.13	16.56	16.67	16.55	16.65	15.84	16.45	17.67	16.8	17.13	17.66
Delaware	10.1	10.68	10.51	10.15	10.63	9.99	9.45	9.87	9.6	10.78	10.02	9.63	9.77	10.55	10.9	9.93	10.47	9.79	9.42	9.73	9.49	9.89	9.94	9.55	8.79	10.09	9.31	9.67	9.6	9.65	9.27	9.42	9.45	10.21	10.25	10.01
D.C.	11.64	12.43	11.58	11.88	11.66	11.58	11.3	11.7	11.46	12.05	11.77	11.68	11.3	11.73	11.89	11.92	11.57	11.66	11.15	11.13	11.77	11.98	12.18	11.87	11.93	12.35	10.56	12.67	11.6	12.08	11.4	12.34	11.76	12.18	12.51	12.67
Georgia	9.62	9.47	9.32	9.49	9.64	9.93	10	9.7	9.82	9.75	9.92	9.79	9.79	9.99	10.18	10.03	9.79	9.92	10.09	10.17	10.27	10.01	9.99	9.9	10.37	9.38	9.78	9.54	9.62	9.7	9.64	9.74	9.72	9.5	9.99	8.69
Illinois	0.4	8.5	8.65	8.66	9.02	8.72	8.98	8.87	9.12	9.17	9.08	8.82	8.29	8.5	9.66	9.04	9.21	9.05	8.82	9.12	9	9.16	8.92	8.6	9.58	8.51	8.69	8.95	8.84	8.96	8.95	8.96	8.94	9.26	9.02	8.62
Maine	12.31	12.29	12.36	12	12.15	11.6	11.86	12.27	12.02	12.37	12.39	11.97	12.36	12.59	12.49	11.83	12.09	11.97	12.19	12.08	11.86	12.02	12.75	11.68	12.48	13.12	12.07	12.09	12.18	11.74	11.88	12.04	11.8	12.34	14.09	12.47
Maryland	10.95	10.96	10.96	11	11.16	11.04	10.74	10.75	10.85	11.22	11.04	11.27	11.08	11.45	10.79	11.07	10.98	10.62	10.32	10.59	10.25	10.63	10.64	10.89	10.84	11.08	10.12	10.48	10.3	10.47	10.13	10.12	10.23	10.6	10.32	10.81
Massachusetts	15.45	16.02	15.56	15.56	14.85	15.34	15.74	15.71	16.28	15.87	14.91	14.94	14.34	14.63	14.15	14.15	14.06	15.07	15.33	16.24	16.91	16.07	15.91	15.45	16.77	17.67	17.12	16.36	16.13	16.35	16.68	16.64	17.25	16.92	16.27	16.78
Michigan	10.22	10.59	10.39	10.42	10.71	10.69	10.66	10.74	10.8	10.86	10.96	10.89	10.84	11.24	11.08	10.81	11.54	11.09	10.91	11.04	10.85	10.79	11.08	10.95	10.76	11.5	11.48	11.23	11.45	11.03	11.5	10.97	10.88	11.21	11.16	11.02
New Hampshire	14.58	14.79	14.55	14.49	14.43	14.03	13.99	14.3	14.41	14.56	14.67	14.57	14.33	14.9	14.7	14.48	14.79	14.72	14.64	14.67	14.98	15.2	14.8	14.97	15.56	16.96	15.35	15.78	16.36	15.58	15.55	15.21	15.9	16.08	15.83	15.93
New Jersey	11.99	11.84	12.07	12.02	12.42	13.4	13.23	13.19	12.74	11.7	11.62	11.58	11.94	12.01	12.08	12.22	12.97	13.33	12.91	12.97	12.35	11.35	11.56	11.62	12.14	12.49	11.55	11.72	12.24	12.8	12.66	12.55	12.4	11.77	11.83	12
New York	13.43	13.59	13.58	13.79	13.59	15.12	15.68	15.57	15.76	14.85	13.99	13.75	13.89	13.43	14.22	13.79	14.56	15.98	16.12	15.95	16.13	15.02	13.91	13.44	14.41	13.58	13.36	13.33	13.71	15.11	16.05	15.52	16.07	14.98	13.77	13.12
Ohio	9.65	9.89	9.86	9.94	9.91	9.82	9.63	9.78	10.12	10.22	10.14	9.99	9.69	9.99	10.07	10.27	10.1	9.89	9.72	10.14	10.11	10.27	10.1	9.67	9.58	10.32	9.99	10.09	10.09	9.96	9.83	9.72	9.87	10.12	10.04	9.67
Oregon	8.62	8.87	8.87	8.87	8.92	8.8	8.83	8.87	8.96	9.05	8.98	8.94	8.72	8.75	9.02	8.91	8.96	8.89	8.9	8.9	8.72	9.04	8.92	8.77	8.88	8.76	8.98	9.07	9.07	8.94	9.41	9.49	6.95	9.03	9.15	8.87
Pennsylvania	9.44	9.59	9.46	9.52	9.34	9.12	9.04	9.08	9.03	9.22	9.15	9.01	8.98	9.3	9.02	9.13	9.14	8.96	8.9	8.93	8.85	8.86	8.92	8.81	9.16	9.42	8.86	8.78	9.02	8.81	8.71	8.71	8.69	8.79	8.97	8.92
Rhode Island	15.77	16.08	15.65	15.13	14.37	14.47	14.19	14.63	14.79	14.48	14.59	14.29	15.44	16.02	15.08	15.44	13.8	14.52	15.14	15.47	15.3	15.4	15.85	15.37	17.53	17.68	16.34	16.08	15.61	15.15	15.64	15.72	16.76	16.93	17.32	17.4
Texas	7.77	7.84	7.76	7.64	7.71	7.78	7.65	7.65	8.23	8.35	8.23	8.21	8.4	8.55	8.39	8.37	8.27	8.32	8.3	8.17	8.16	8.14	8.31	8.16	8.18	8.53	8.32	8.16	8.23	8.2	8.06	8.21	7.93	7.93	8.23	7.7
Monthly Average	11.17	11.86	11.73	11.67	11.72	11.86	11.86	11.95	12.02	12.01	11.76	11.58	11.60	11.89	11.90	11.73	11.86	12.06	12.05	12.16	12.19	12.08	11.94	11.50	12.13	12.41	11.85	11.97	12.01	12.17	12.22	12.28	12.21	12.33	12.33	12.09

Regulated States	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Alabama	10.78	11.07	10.82	11.04	11.02	11.16	11.11	11.03	11.05	11.49	11.34	11.58	11.48	11.94	11.73	11.44	11.5	11.66	11.54	11.57	11.77	11.61	11.65	11.5	11.31	11.27	11.5	11.42	11.23	11.29	11.14	11.23	11.23	11.24	11.5	11.19
Alaska	17.58	17.62	17.65	18.34	18.38	18.64	18.61	18.7	17.6	17.68	17.69	17.51	18.33	18.72	19.89	20.35	20.63	20.76	19.5	18.49	18.47	18.6	18.59	19.09	18.87	18.72	18.83	18.52	18.9	18.59	19.22	19.1	19.18	19.85	19.44	19.66
Arizona	9.59	9.87	9.75	10.08	11.07	11.2	11.24	11.1	10.95	10.55	9.57	9.54	9.66	9.75	9.78	10.23	11.3	11.23	11.54	10.83	10.57	10.89	9.84	9.91	9.95	10.25	10.09	10.44	11.32	11.27	11.48	11.24	11.02	10.85	9.89	9.66
Arkansas	7.82	7.97	7.96	7.99	8.2	8.47	8.24	8.28	8.43	8.19	8.12	8.12	8	8.25	7.98	8.5	8.56	8.77	8.7	8.72	8.74	8.38	8.46	8.24	8.47	8.63	8.64	7.51	7.54	7.49	7.44	7.51	7.42	7.05	7.35	7.29
Colorado	8.58	8.92	8.99	9.48	9.55	10.25	10.01	10.2	10.33	9.92	0.81	9.36	9.17	9.47	9.55	9.64	9.84	10.72	10.36	10.35	10.38	10.16	9.71	9.5	9.17	9.64	9.62	10.02	10.09	10.78	10.26	10.53	10.41	10.62	10.18	9.62
Florida	9.5	9.64	9.2	9	8.91	8.92	8.87	9.05	8.85	8.94	9.03	8.87	9.45	9.76	9.61	9.55	9.29	9.6	9.49	9.19	9.5	9.58	9.5	9.7	9.94	10.05	9.53	9.23	9.29	9.04	8.92	8.93	8.93	9.32	9.79	9.66
Hawaii	24.74	23.68	23.99	23.31	23.59	24.69	24.8	25.01	25.25	24.9	25.94	25.73	26.35	26.6	26.41	26.46	26.36	26.95	26.5	26.18	26.3	26.67	28.27	28.91	28.87	28.7	29.94	28.83	29.35	29.56	30.53	30.11	30.12	29.85	31.69	32.42
Idaho	7.44	7.59	7.66	7.69	7.75	8.31	8.12	8.02	7.66	7.8	7.86	7.46	7.43	7.64	7.73	7.99	7.79	9.35	8.21	8.2	7.94	8.12	7.86	7.85	7.82	7.93	7.99	8.04	8.16	8.38	8.06	8.14	7.74	7.82	7.63	7.44
Indiana	9.3	9.47	9.59	9.75	9.57	9.56	9.55	9.74	10.25	10.32	10.63	10.37	10.1	10.38	10.26	10.41	10.3	10.37	10.17	10.56	10.63	10.56	10.73	10.17	10.07	10.32	10.52	10.4	10.2	10.3	10.31	10.35	10.57	10.4	10.63	10.33
Iowa	8.2	8.54	8.45	8.67	9.44	10.68	10.97	11.24	9.71	8.59	8.6	8.03	8.67	8.7	8.48	8.96	9.39	10.84	11.58	11.44	10.3	8.56	8.82	8.63	8.97	9.33	9.23	9.23	9.68	10.95	11.69	10.72	10.32	9.32	9.16	8.7
Kansas	9.9	10.25	10.37	10.28	10.44	10.58	10.42	10.41	10.4	10.57	10.12	9.95	9.73	10.22	10.28	10.53	10.57	10.99	10.74	11.13	10.84	10.68	10.22	10.04	10.05	10.37	10.39	10.58	10.39	10.66	10.8	10.88	10.26	10.61	10.03	9.81
Kentucky	9.1	9.31	9.32	9.45	9.4	9.47	9.29	9.21	9.66	9.73	9.9	9.59	9.51	9.78	9.59	9.76	9.6	9.67	9.66	9.85	10.17	9.8	10.07	9.57	9.12	9.86	9.6	9.81	9.49	9.53	9.4	9.3	9.67	9.54	9.87	9.69
Louisiana	8.35	8.41	8.89	8.6	8.43	8.11	8.14	8.51	8.67	8.55	8.71	9.05	7.64	9.23	9.09	8.87	8.98	9.39	9.16	8.94	9.01	8.94	8.94	8.8	8.94	8.95	9.36	9.23	8.65	8.48	8.77	8.7	8.29	8.19	8.66	8.81
Minnesota	9.49	9.5	9.46	9.78	9.95	9.88	10.1	10.16	10.64	9.9	10.21	9.23	9.58	11.06	9.78	10.59	10.72	11.21	11.43	10.91	11	10.64	9.89	9.64	9.71	10.01	9.9	9.88	10.6	11.26	11.06	10.84	11.33	10.45	10.21	9.89
Mississippi	10.02	9.84	9.8	9.38	9.31	9.52	9.25	9.3	9.3	9.78	9.91	10.04	10.11	10.41	10.47	10.47	10.29	10.27	10.12	9.94	10.18	10.14	10.37	10.42	10.4	10.9	11.05	10.89	10.83	10.57	9.95	10.05	10	10.4	10.9	10.8
Missouri	7.88	8.17	8.13	8.22	9.35	10.66	10.38	10.52	9.41	8.57	8.63	8.66	8.1	8.38	8.4	8.55	10.01	10.81	10.77	11.19	9.31	8.92	8.74	8.31	8.12	8.48	8.68	8.51	10.05	10.88	10.89	10.24	8.92	8.54	8.25	8.19
Montana	9.5	9.87	10.24	10.27	10.44	10.5	10.32	10.16	10.36	10.32	10.23	10.05	9.89	9.96	10.04	10.22	10.46	10.49	10.26	10.02	10.23	10.22	10.16	10.06	9.9	9.96	10.02	10.13	10.33	10.48	10.41	10.01	10.27	10.28	10.11	10.13
Nebraska	8.31	8.39	8.63	8.66	8.79	9.57	9.56	9.35	9.3	8.54	8.41	8.44	8.4	8.52	8.88	8.72	8.97	9.68	9.57	9.3	9.35	8.45	8.35	8.72	8.52	8.41	8.69	8.74	9	9.26	9.68	9.48	9.42	8.76	8.76	8.54
Nevada	8.15	8.67	0.3	8.04	8.05	7.92	7.7	7.98	8.02	7.87	7.62	7.51	7.8	7.95	7.83	8.02	7.85	7.59	7.92	8.12	8.02	8.67	8.23	8.04	8.04	8.15	8.08	7.73	7.8	7.64	7.85	8.16	7.61	7.85	7.59	7.59
New Mexico	9.54	9.38	9.36	9	9.26	10.12	10.45	10.64	10.45	9.89	9.44	9.75	9.39	10.13	9.99	9.97	10.26	10.93	11.24	10.7	10.41	9.97	9.78	9.44	9.48	9.65	9.86	9.78	9.69	10.7	10.91	10.81	10.31	10.15	9.89	9.75
North Carolina	8.56	8.7	8.52	8.49	8.56	8.63	8.98	8.88	8.72	8.78	8.34	8.3	8.4	8.65	8.55	8.2	8.64	8.32	8.82	8.62	8.76	8.65	8.15	8.37	8.5	9.14	8.64	8.66	8.33	8.58	8.96	8.82	8.58	9.06	8.43	8.58
North Dakota	8.44	8.96	8.92	9.31	9.13	9.3	9.36	9.57	9.79	9.29	9.1	8.78	8.76	8.98	8.84	9.12	9.37	9.78	9.55	9.85	9.7	9.19	8.68	8.68	8.57	8.59	8.79	8.89	9.2	9.68	9.47	9.63	9.71	9.18	8.97	8.69
Oklahoma	6.82	6.96	6.72	6.85	7.21	7.8	8.01	8.16	8.49	8.12	7.01	7.45	7.81	7.91	7.5	8.04	7.88	8.15	8.27	8.43	8.5	8.11	7.66	7.44	7.85	7.69	7.61	7.59	7.52	8.52	8.1	8.43	8.27	8.02	7.22	7.51
South Carolina	9.87	10.09	9.9	9.78	9.85	10.58	10.46	10.36	10.47	9.94	10.24	10.4	10.14	10.7	10.23	10.48	10.21	10.66	10.71	10.76	11	8.77	10.41	10.53	11.19	8.22	10.55	10.48	10.09	10.76	10.7	8.04	9.85	9.83	10.46	10.11
South Dakota	8.94	9.07	9.22	9.32	9.55	9.71	9.92	9.57	10.02	9.77	9.64	9.4	8.93	9.14	9.46	9.63	9.68	9.99	9.86	9.77	10.01	9.73	9.63	9.48	9.29	9.32	9.12	9.15	9.41	9.68	9.53	9.95	9.82	9.88	9.1	9.38
Tennessee	9.73	9.7	9.73	9.64	9.56	10.1	10.24	10.26	10.56	10.3	10.41	10.63	10.54	10.47	10.43	10.27	10.33	10.77	10.67	10.62	10.58	10.26	10.52	10.57	10.17	10.39	10.78	10.35	10.22	10.43	10.41	10.44	10.32	10.19	10.65	10.64
Utah	8.19	8.29	8.25	8.49	9.33	9.78	9.13	9.18	9.45	8.85	8.45	8.04	8.07	8.33	8.52	8.47	9.36	9.48	9.26	8.96	9.03	8.76	8.14	7.9	7.87	8.24	8.21	8.24	9.11	8.78	8.62	8.55	8.79	8.41	7.93	7.34
Vermont	14.25	14.34	14.39	14.49	14.82	14.58	14.6	13.97	14.73	14.86	14.82	14.37	14.34	14.54	14.34	14.73	14.83	14.8	14.71	12.17	12.54	14.7	14.91	14.47	15.15	15.05	15.14	15.07	15.29	15.44	15.06	15.01	15.11	15.31	15.27	15.44
Virginia	8.19	8.15	8.09	8.16	8.19	8.29	7.86	7.84	7.77	7.6	7.77	7.66	8.02	7.41	7.74	7.86	7.81	7.87	8.32	8.41	8.33	8.43	8.16	8.32	8.29	8.48	8.33	8.32	8.33	8.48	8.39	8.44	8.39	8.31	8.39	8.32
Washington	8.28	8.52	8.48	8.3	8.22	8.35	8.33	8.27	8.44	8.61	8.54	8.44	8.37	8.41	8.55	8.37	8.4	8.54	8.47	8.38	8.63	8.74	8.68	8.66	8.65	8.84	8.86	8.66	8.62	8.59	8.6	8.67	8.63	8.84	8.78	8.71
West Virginia	9.06	9.47	9.55	9.49	9.35	9.2	9.06	9.2	9.31	9.61	0.77	9.27	9.57	9.87	9.79	9.94	9.68	9.37	9.21	9.35	9.51	9.67	9.82	9.23	9.12	9.96	9.68	9.64	9.59	9.25	9.25	8.98	9.02	9.07	9.68	8.75
Wisconsin	10.7	10.81	10.81	10.86	11.07	11.48	11.35	11.08	10.72	10.63	10.59	10.46	10.74	11.04	10.94	10.85	11.45	11.52	11.2	11.09	11.11	10.67	11.06	10.83	10.78	10.95	10.69	10.9	11.3	10.89	10.95	11.02	11.08	10.91	11.02	10.54
Wyoming	8.93	9.22	9.39	9.42	9.74	9.77	9.49	9.45	9.68	9.37	9.74	9.11	9.19	9.63	9.55	9.97	10.01	10.22	9.77	9.66	9.83	10	9.64	9.5	9.32	9.5	9.59	9.78	9.96	10.24	9.75	9.61	9.74	9.21	9.63	9.21
Monthly Average	9.81	9.95	9.71	9.99	10.17	10.48	10.42	10.44	10.44	10.24	9.64	10.03	10.05	10.36	10.31	10.46	10.62	10.93	10.83	10.66	10.63	10.46	10.41	10.32	10.32	10.42	10.53	10.44	10.59	10.80	10.80	10.66	10.62	10.52	10.52	10.38

Industrial

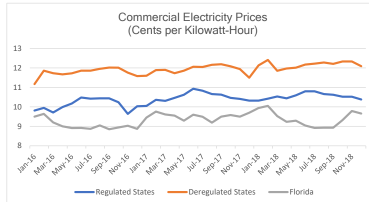
Month	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Competitive States																																				
California	10.52	10.4	10.39	10.66	11.66	13.61	14.05	14.07	13.65	10.65	11.84	10.89	10.69	14.45	11.17	9.89	12.2	15.06	14.46	14.27	14.32	14.47	12.76	11.35	11.54	14.83	11.78	11.03	12.64	14.73	15.31	15.5	14.61	14.57	13.27	11.91
Connecticut	13.01	13.5	13.44	12.91	13.11	12.73	13.05	12.89	12.81	12.73	12.61	12.73	13.32	15.95	13.17	12.94	13.25	13.03	13.7	13.24	13.29	13.28	13.32	13.14	15.57	17.13	13.92	13.7	12.59	15.04	13.48	13.79	14.16	13.68	13.92	14.12
Delaware	8.41	7.96	8.34	8.03	7.98	7.94	7.95	8.08	8.21	8.38	7.6	7.76	8.06	10.55	8.31	8.11	7.86	7.81	7.45	7.44	7.42	7.59	7.52	7.73	8.56	10.09	7.33	7.46	7.08	7.37	7.71	7.76	7.86	7.69	7.8	7.83
D.C.	9.44	9.07	9.06	9.09	8.93	10.4	8.62	9.02	8.57	8.67	8.55	8.56	8.02	11.73	8.26	8.47	8.3	8.34	8.47	7.95	8.13	8.17	8.2	8.08	8.22	12.35	7.94	8.37	7.99	8.54	7.98	8.46	8.34	8.14	7.79	8.66
Georgia	5.44	5.06	4.98	5.19	5.29	6.19	6.7	6.07	6.36	5.76	5.65	5.85	5.4	9.99	5.64	5.69	5.59	6.1	6.68	6.43	6.3	5.65	5.73	5.55	7.09	9.38	5.11	5.49	5.54	6.28	6.12	6.22	6.2	5.26	6.25	5.24
Illinois	6.29	6.34	6.28	6.27	6.33	6.34	6.46	6.64	6.63	6.67	6.45	6.16	6.33	8.5	6.75	6.31	6.51	6.52	6.33	6.57	6.34	6.43	6.34	6.18	7.59	8.51	6.24	6.47	6.45	6.45	6.62	6.62	6.42	6.82	6.73	6.72
Maine	8.88	9.17	9.12	8.83	8.79	8.37	9.21	9.72	9.05	8.5	9.04	9.25	9.56	12.59	9.61	9.3	9.19	9.09	8.97	9.46	9.14	8.8	8.84	9.22	9.68	13.12	9.1	8.49	8.94	8.39	8.88	8.99	8.58	8.8	9.79	9.2
Maryland	7.86	8.33	7.84	7.91	8.11	7.64	7.47	7.86	7.78	7.77	7.81	7.96	8.59	11.45	8.34	8.28	8.36	8.07	8.11	8.43	8.25	8.53	8.33	8.39	9.41	11.08	8.11	8.35	8.15	7.88	8.1	7.9	7.95	7.9	8.04	8.36
Massachusetts	13.08	13.32	13.23	12.96	12.7	12.88	13.24	13.36	13.61	13.45	13.2	13.59	13.5	14.63	13.24	13.02	12.83	13.56	13.88	14.18	14.22	13.85	13.96	14.08	15.09	17.67	14.41	14.42	14.3	14.45	14.43	13.81	14.57	14.31	14.4	14.71
Michigan	6.89	6.68	6.89	6.72	7.01	7	7.25	7.34	7.11	7	7	7.06	7.38	11.24	7.39	7.28	7.47	7.42	7.4	7.12	7.2	7.04	7.11	7.2	7.25	11.5	7.45	7.31	7.29	7.25	7.51	7.09	7.2	7.29	7.06	7.24
New Hampshire	12.7	12.71	12.4	12.35	12.12	11.93	12.1	12.32	12.33	12.27	12.32	12.65	12.74	14.9	12.32	12.18	11.98	12.03	12.19	12.17	12.32	12.5	12.18	12.89	13.88	16.96	13.23	13.36	13.53	9.39	13.33	13	13.12	13.12	13.41	13.7
New Jersey	10.06	9.84	10.17	9.67	10.05	10.68	11.03	10.82	10.71	9.1	9.71	9.87	10.34	12.01	9.91	10	10.18	11.13	10.62	10.64	10.28	9.6	9.26	9.84	10.95	12.49	9.57	9.52	9.62	10.4	10.11	10.45	10.26	9.8	9.72	10.1
New York	5.51	6.11	5.99	5.96	5.75	6.73	5.56	6.28	6.18	5.95	6.59	5.83	5.87	13.43	5.87	5.88	6.19	6.12	5.92	6.2	6.19	6.15	5.76	5.94	6.37	13.58	5.48	5.58	6.54	5.98	6.28	6.06	6.07	6.06	5.76	5.61
Ohio	6.79	6.8	6.8	6.76	6.87	6.74	6.9	6.81	6.95	6.93	6.88	7.01	6.59	9.99	6.86	6.53	6.69	6.69	6.72	6.91	6.94	6.91	6.89	6.68	7.02	10.32	6.56	6.73	6.66	6.76	6.66	6.6	6.56	6.73	6.64	6.59
Oregon	5.87	6	5.84	5.89	6.03	6.33	6.5	6.47	6.16	6.2	6.23	5.79	6.06	8.75	6.24	5.78	6.01	6.25	6.47	6.19	6.13	6.02	6.2	5.99	5.94	8.76	6.03	6	6.06	5.78	5.04	5.92	8.89	6.15	6.51	6.04
Pennsylvania	7.11	7.04	6.98	6.9	6.86	6.82	6.84	7.06	6.99	6.86	6.8	6.81	6.99	9.3	6.93	6.87	6.75	6.58	6.65	6.64	6.68	6.81	6.66	6.75	7.6	9.42	6.5	6.59	6.59	6.65	6.65	6.62	6.6	6.67	6.7	6.7
Rhode Island	14.14	13.68	13.57	13.44	13.65	13.29	13.45	13.46	13.34	13.21	13.4	13.53	14.22	16.02	14.18	14.43	14.16	14.1	14.85	14.99	14.76	14.8	14.6	15.17	16.19	17.68	15.22	14.85	14.54	14.1	14.83	14.84	15.17	15.55	15.82	17.09
Texas	5.06	5.02	5.27	4.82	5.08	5.33	5.41	5.32	5.52	5.34	5.38	5.31	5.47	8.55	5.32	5.54	5.68	5.53	5.72	5.39	5.43	5.32	5.17	5.39	5.7	8.53	5.29	5.2	5.57	5.84	6.2	5.86	5.4	5.39	5.47	5.14
Monthly Average	8.73	8.72	8.70	8.58	8.68	8.94	8.99	9.09	9.00	8.64	8.73	8.70	8.84	11.89	8.86	8.69	8.84	9.08	9.14	9.12	9.07	9.00	8.82	8.87	9.65	12.41	8.85	8.83	8.89	8.96	9.18	9.19	9.33	9.11	9.17	9.16

Regulated States	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Alabama	5.4	5.32	5.59	5.91	6.03	6.48	6.59	6.43	6.34	6.31	5.95	6.38	5.84	11.94	6.13	6.04	6.24	6.52	6.6	6.41	6.52	6.09	6.1	5.95	6.07	11.27	5.8	5.89	6.24	6.37	6.24	6.32	6.31	5.98	6.13	5.87
Alaska	13.76	14.04	15.36	16.11	16.1	15.71	16.52	15.08	14.98	15.96	15.8	16.08	16.99	18.72	17.9	15.84	16.77	16.89	16.98	15.87	15.42	15.53	16.21	16.93	17.5	18.72	16.81	18.21	17.51	18.77	20.09	17.86	15.74	17.14	14.56	16.46
Arizona	5.36	5.32	5.39	5.63	6.11	6.39	6.69	7	6.79	6.39	5.7	5.83	5.92	9.75	5.76	6.07	6.79	6.93	7.41	7.31	6.69	6.51	6.09	5.76	5.91	10.25	5.89	6	6.89	6.87	7.68	7.74	6.94	6.7	6	5.96
Arkansas	5.58	5.49	5.53	5.27	5.62	6.41	6.5	6.5	6.56	6.09	5.86	6.11	5.65	8.25	5.52	5.64	5.85	6.26	6.55	6.54	6.58	5.86	5.88	5.72	6.01	8.63	5.55	5.08	5.23	5.49	5.73	5.64	5.43	5.02	5.21	5.14
Colorado	6.62	6.73	6.71	6.92	6.83	7.41	7.43	7.38	7.82	7.4	7.45	7.5	6.89	9.47	7.33	7.08	7.15	7.61	7.66	7.76	7.75	7.59	7.37	6.9	7.18	9.64	7.04	7.18	7.24	7.52	7.5	7.3	7.37	7.48	7.16	7.01
Florida	7.8	7.73	7.76	7.53	7.48	7.79	7.97	7.99	7.91	7.82	7.75	7.7	7.7	9.76	7.87	7.71	7.71	8.01	8.05	7.82	7.93	7.86	7.95	7.8	8.22	10.05	7.82	7.55	7.6	7.68	7.65	7.64	7.61	7.74	7.93	7.77
Hawaii	20.8	19.66	19.86	19.31	19.78	20.75	21.01	21.17	21.43	20.79	21.88	21.68	22.24	26.6	22.41	22.54	22.39	23.03	22.63	22.41	22.58	22.86	24.44	25.01	24.92	28.7	25.96	25	25.7	25.56	26.54	26.23	26.16	25.8	27.58	28.52
Idaho	4.97	5.91	5.98	6.1	6.33	7.66	7.09	7.14	6.74	6.1	5.71	5.67	5.71	7.64	5.95	5.86	6.58	7.87	7.36	7.41	6.97	5.96	5.82	5.63	5.76	7.93	5.85	6.16	6.95	7.41	7.06	7.18	6.12	5.66	5.46	5.67
Indiana	6.51	6.54	6.66	7.13	6.98	6.92	7	7.13	7.06	7.42	7.38	7.38	7.35	10.38	7.37	7.47	7.42	7.35	7.43	7.41	7.49	7.53	7.63	7.27	7.23	10.32	7.12	7.16	7.06	7.21	7.17	7.07	7.2	7.16	7.33	7.15
Iowa	5.41	5.25	5.41	5.04	5.71	7.57	8.04	7.99	7.16	5.34	5.11	5.08	5.5	8.7	5.27	5.38	5.46	7.47	8.42	8.1	7.53	5.33	5.39	5.49	5.82	9.33	5.99	5.82	5.7	8.13	8.36	8.3	7.59	5.78	5.74	5.36
Kansas	7.35	7.46	7.49	7.4	7.43	7.6	7.51	7.43	7.44	7.48	7.33	7.29	7.5	10.22	7.5	7.6	7.77	7.37	7.81	7.66	7.65	7.57	7.67	6.8	7.48	10.37	6.84	6.97	7.92	7.51	7.6	7.48	7.78	7.52	7.16	7.38
Kentucky	5.33	5.19	5.2	5.35	5.2	5.71	5.77	5.66	5.92	5.72	5.7	5.89	5.63	9.78	5.61	5.54	5.53	5.57	5.76	5.69	5.75	5.59	5.71	5.43	5.58	9.86	5.17	5.4	5.62	5.83	5.49	5.25	5.5	5.4	5.71	5.56
Louisiana	4.94	4.72	5.21	4.83	4.78	4.42	4.8	5.23	5.54	5.33	5.18	5.56	4.04	9.23	5.7	5.07	5.29	5.87	6.12	5.71	5.72	5.64	5.53	5.14	5.11	8.95	5.69	5.35	5.15	5.12	5.6	5.62	5.12	4.94	5.41	5.36
Minnesota	6.95	7.04	7.07	7.09	7.17	7.57	7.62	7.68	7.12	7.44	7.31	7.17	7.39	11.06	7.6	7.69	7.71	8.15	8.16	7.6	7.63	7.47	7.13	7.24	7.49	10.01	7.38	7	8	8.07	8.18	7.99	8.26	7.74	7.74	7.57
Mississippi	5.98	5.58	5.61	5.43	5.46	6.07	6.15	6.06	6.08	5.97	5.9	6.17	6.03	10.41	6.04	6.09	5.93	6.37	6.32	6.17	6.12	5.86	5.78	6.02	5.81	10.9	6.07	5.88	6.02	6.3	6.11	6.3	6.09	6.02	6.33	6.29
Missouri	5.72	6.06	5.99	6.2	6.96	8.07	8	7.96	7.43	6.83	6.74	7.06	6.35	8.38	6.33	6.46	7.23	8.12	8.3	8.32	7.49	6.95	6.87	6.55	6.44	8.48	6.46	6.31	7.55	8.16	8.32	7.34	6.9	6.54	6.45	6.22
Montana	4.98	4.79	4.74	4.48	4.79	5.15	5.55	5.46	5.07	5.17	4.85	4.9	4.96	9.96	4.77	4.64	5	5.32	5.54	5.86	5.25	5.39	5.16	5.13	5.03	9.96	4.96	4.73	4.72	4.92	5.76	6.15	5.03	5.55	5.48	5.77
Nebraska	6.88	7.16	8.5	7.41	7.36	8.03	8.9	8.36	7.5	7.2	6.94	7.04	6.92	8.52	8.34	7.6	7.24	8.16	8.68	8.32	7.83	7.06	7.02	7.01	6.95	8.41	8.3	7.53	7.33	7.73	8.42	7.86	7.65	7.2	6.98	7.04
Nevada	4.97	5.13	4.82	4.98	4.84	5.98	8.42	7.84	7.42	6.7	3.19	4.64	4.94	7.95	5.02	5.14	5.18	7.31	7.59	8.23	8.07	5.89	5.02	5.19	5.28	8.15	5.43	5.25	5.37	7.46	7.33	8.09	7.67	5.39	4.79	4.78
New Mexico	5.68	5.12	5.78	5.55	5.8	6.18	5.97	5.89	5.93	5.56	5.74	6.07	5.55	10.13	6.36	6.07	6.04	6.02	6.29	6.48	6.33	6	5.84	5.52	5.65	9.65	6.18	5.8	5.62	5.53	5.97	5.68	5.82	5.76	5.6	5.48
North Carolina	6.14	6.01	5.36	5.99	6.03	6.43	7.04	6.73	6.77	6.32	5.94	6.1	6.11	8.65	5.94	5.95	5.72	6.14	6.9	6.48	6.73	6.28	5.64	5.93	6.23	9.14	5.81	6.05	5.77	6.46	6.84	6.44	6.79	6.05	5.75	6.09
North Dakota	7.91	8.27	8.05	7.06	8.43	8.61	8.43	8.75	8.28	8.21	8.17	8.21	8.46	8.98	8.54	8.71	8.62	8.81	8.69	7.7	7.8	7.62	7.52	8.36	8.23	8.59	8.52	8.51	8.47	8.56	8.56	8.48	8.55	8.37	8.43	8.24
Oklahoma	4.51	4.48	4.43	4.43	4.67	5.2	5.18	5.2	5.39	5.2	4.8	5.23	5.19	7.91	5.23	5.22	5.34	5.39	5.58	5.59	5.55	5.19	5.09	5.16	5.18	7.69	4.98	4.99	5.14	5.4	5.34	5.31	5.12	5.16	4.99	5.02
South Carolina	5.84	5.67	5.41	5.77	5.73	6.39	6.65	6.35	6.56	6.07	5.63	6.18	5.82	10.7	5.88	5.89	5.98	6.27	6.5	6.48	6.57	6.2	5.87	6.16	6.89	8.22	6	5.84	5.89	6.34	6.47	5.31	6.2	5.89	7.12	6.2
South Dakota	7.35	7.24	7.6	7.41	7.53	7.77	7.89	7.53	7.76	7.66	7.45	7.42	7.39	9.14	7.97	7.67	7.75	7.76	8.01	8.02	7.88	7.84	7.96	7.77	7.76	9.32	7.71	7.58	7.66	7.74	7.99	8.15	7.99	7.81	7.58	7.44
Tennessee	5.71	5.49	5.47	5.39	5.26	5.81	6.17	6.23	6	5.84	5.78	5.99	6.03	10.47	5.91	5.8	5.74	6.1	6.31	6.01	5.89	5.9	6.02	6.14	5.89	10.39	5.67	5.58	5.63	5.91	5.92	5.26	5.85	5.66	5.89	6.04
Utah	5.74	6.02	6.04	5.99	6.18	7.45	7.05	6.87	6.9	6.22	5.6	5.64	5.89	8.33	6.06	5.18	6.42	7.02	6.99	6.57	6.76	5.59	5.65	5.45	5.47	8.24	5.26	5.37	6.13	6.38	6.21	6.8	5.9	6	5.23	5.51
Vermont	10.34	9.94	10.28	9.63	9.77	10.23	10.27	9.95	10.57	10.16	10.08	10.18	10.2	14.54	10.24	9.94	9.92	10.39	10.18	10.17	10.33	9.76	9.88	10.15	10.62	15.05	10.66	10.21	10.21	10.84	10.58	10.54	10.59	10.31	10.51	10.75
Virginia	6.96	6.69	6.64	6.73	6.63	6.68	6.71	6.68	6.38	6.44	6.51	6.45	6.54	7.4	6.48	6.41	6.57	6.65	6.78	6.66	6.74	6.84	6.68	6.45	6.74	8.48	6.9	6.8	6.85	6.76	6.91	6.9	6.83	6.91	6.88	6.78
Washington	4.4	4.62	4.4	4.41	4.28	4.47	4.73	4.68	4.57	4.5	4.53	4.36	4.46	8.41	4.54	4.7	4.6	4.62	4.71	4.82	4.72	4.73	4.81	4.52	4.56	8.84	4.6	4.75	4.37	4.42	4.84	5.23	4.74	4.84	5.02	4.71
West Virginia	6.43	6.55	6.47	6.53	6.55	6.56	6.69	6.54	6.52	6.52	6.79	6.66	6.7	9.87	6.73	6.78	6.72	6.55	6.6	6.64	6.48	6.59	6.64	6.48	6.47	9.96	6.58	6.63	6.63	6.52	6.56	6.45	6.29	6.1	6.38	6.01
Wisconsin	7.5	7.64	7.57	7.38	7.71	8.17	8.17	8.09	7.69	7.31	7.33	7.22	7.66	11.04	7.57	7.69	7.73	8.11	8.23	7.6	7.69	7.54	7.7	7.65	7.7	10.95	7.33	7.55	7.71	7.57	7.91	7.94	7.74	7.68	7.67	7.32
Wyoming	6.57	7.08	6.98	6.96	7.04	6.97	6.78	7.09	6.87	7	6.85	6.88	6.78	9.63	7.17	6.85	7.19	6.9	6.81	6.71	6.83	7.1	6.74	6.8	6.6	9.5	6.94	6.79	6.95	6.7	6.67	6.59	6.8	6.6	6.46	6.51
Monthly Average	6.86	6.85	6.95	6.89	7.05	7.53	7.74	7.64	7.53	7.29	7.06	7.20	7.16	10.36	7.36	7.22	7.38	7.79	7.94	7.77	7.67	7.32	7.30	7.26	7.39	10.42	7.37	7.30	7.48	7.80	7.99	7.83	7.63	7.39	7.35	7.36

Commercial

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
Regulated States	9.81	9.95	9.71	9.99	10.17	10.48	10.42	10.44	10.44	10.24	9.64	10.03	10.05	10.36	10.31	10.46	10.62	10.93
Deregulated States	11.17	11.86	11.73	11.67	11.72	11.86	11.86	11.95	12.02	12.01	11.76	11.58	11.60	11.89	11.90	11.73	11.86	12.06
Florida	9.5	9.64	9.2	9	8.91	8.92	8.87	9.05	8.85	8.94	9.03	8.87	9.45	9.76	9.61	9.55	9.29	9.6

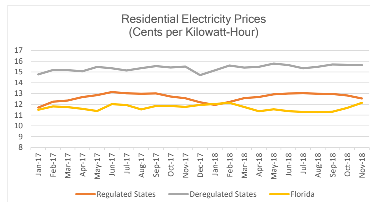
	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Regulated States	10.83	10.66	10.63	10.46	10.41	10.32	10.32	10.42	10.53	10.44	10.59	10.8	10.8	10.66	10.62	10.52	10.52	10.38
Deregulated States	12.05	12.16	12.19	12.08	11.94	11.50	12.13	12.41	11.85	11.97	12.01	12.17	12.22	12.28	12.21	12.33	12.33	12.09
Florida	9.49	9.19	9.5	9.58	9.5	9.7	9.94	10.05	9.53	9.23	9.29	9.04	8.92	8.93	8.93	9.32	9.79	9.66



Residential

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
Regulated States	11.37	11.61	12.01	12.26	12.49	12.56	12.57	12.63	12.42	12.47	12.34	11.78	11.7	12.24	12.35	12.67	12.85	13.14
Deregulated States	14.68	14.85	15.08	15.02	15.36	15.19	14.9	15.03	15.2	15.14	15.13	14.71	14.78	15.18	15.17	15.07	15.47	15.34
Florida	11.5	11.33	11.24	11.07	10.86	11.08	11.18	11.47	11.14	10.98	11.08	10.92	11.5	11.81	11.74	11.58	11.38	12.02

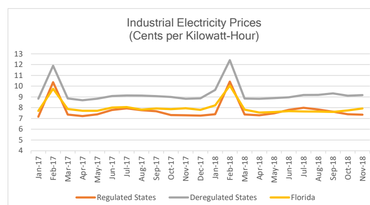
	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Regulated States	13.02	12.98	13.01	12.73	12.56	12.19	11.94	12.22	12.57	12.68	12.93	13	13.04	12.98	12.96	12.82	12.54	12.18
Deregulated States	15.14	15.36	15.55	15.42	15.50	14.71	15.15	15.60	15.41	15.48	15.78	15.64	15.34	15.48	15.70	15.67	15.64	15.35
Florida	11.93	11.53	11.85	11.85	11.76	11.94	12.03	12.14	11.75	11.36	11.54	11.37	11.29	11.27	11.31	11.67	12.14	11.86



Industrial

	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
Regulated States	6.86	6.85	6.95	6.89	7.05	7.53	7.74	7.64	7.53	7.29	7.06	7.2	7.16	10.36	7.36	7.22	7.38	7.79
Deregulated States	8.73	8.72	8.7	8.58	8.68	8.94	8.99	9.09	9	8.64	8.73	8.7	8.84	11.89	8.86	8.69	8.84	9.08
Florida	7.8	7.73	7.76	7.53	7.48	7.79	7.97	7.99	7.91	7.82	7.75	7.7	7.7	9.76	7.87	7.71	7.71	8.01

	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Regulated States	7.94	7.77	7.67	7.32	7.3	7.26	7.39	10.42	7.37	7.3	7.48	7.8	7.99	7.83	7.63	7.39	7.35	7.36
Deregulated States	9.14	9.12	9.07	9	8.82	8.87	9.65	12.41	8.85	8.83	8.89	8.96	9.18	9.19	9.33	9.11	9.17	9.16
Florida	8.05	7.82	7.93	7.86	7.95	7.8	8.22	10.05	7.82	7.55	7.6	7.68	7.65	7.64	7.61	7.74	7.93	7.77



TALLAHASSEE
1500 Mahan Drive
Suite 200
Tallahassee, Florida 32308
(850) 224-4070 Tel
(850) 224-4073 Fax

Nabors Giblin & Nickerson P.A.
ATTORNEYS AT LAW

TAMPA
2502 Rocky Point Drive
Suite 1060
Tampa, Florida 33607
(813) 281-2222 Tel
(813) 281-0129 Fax

FORT LAUDERDALE
110 East Broward Boulevard
Suite 1700
Fort Lauderdale, Florida 33301
(954) 315-3852 Tel

March 1, 2019

Ms. Amy Baker,
Coordinator Office of Economic & Demographic Research
111 West Madison Street,
Suite 574
Tallahassee, FL 32399-6588
Baker.amy@leg.state.fl.us

RE: Serial #18-10 - Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice

Dear Ms. Baker,

Enclosed for the Financial Impact Estimating Conference's (FIEC) consideration at the FIEC workshop scheduled for March 4, 2019, please find JEA's Report on the estimated financial impacts to JEA and other municipal utilities and electric cooperatives of the proposed constitutional amendment entitled, "Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice."

Sincerely,

Evan J. Rosenthal, Esq.
Nabors, Giblin & Nickerson, P.A.

21 West Church Street
Jacksonville, FL 32202

ELECTRIC

WATER

SEWER

IMPACT OF PROPOSED CONSTITUTIONAL AMENDMENT ON JEA

JEA is a municipally-owned electric utility owned by the City of Jacksonville. Currently the largest community-owned utility in Florida and the eighth largest in the United States, JEA serves an estimated 466,000 electric customers.

The proposed constitutional amendment entitled, *"Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice"* (the "Amendment"), purports to allow JEA and other municipally-owned electric utilities and electric cooperatives (hereafter collectively referred to as "municipal utilities") the choice of whether or not to participate in the competitive retail electricity market upon the restructuring called for under the Amendment. Specifically, section (d) of the Amendment provides as follows:

> Nothing in this section shall be construed to affect the existing rights or duties of electric cooperatives, municipally-owned electric utilities, or their customers and owners in any way, except that electric cooperatives and municipally-owned electric utilities may freely participate in the competitive wholesale electricity market and may chose, at their discretion, to participate in the competitive retail electricity market.

This language creates the illusion that municipal utilities will be insulated from the Amendment's effects by virtue of their ability to "opt-out" of retail competition. However, in reality, JEA and other municipal utilities will face substantial economic exposure under the restructuring called for by the Amendment. Municipal utilities will be unable to escape the Amendment's destabilizing effects on the wholesale electricity market, from which municipal utilities are unable to simply "opt-out." Some of the other anticipated impacts of the Amendment on JEA and other municipal utilities are as follows:

(1) By limiting the ability of investor owned utilities ("IOUs") to participate in the generation of electricity, municipal utilities that currently purchase power from IOUs will have those sources disrupted. As a result, existing power purchase agreements ("PPA") between municipal utilities and the IOUs may be abrogated and municipal utilities would be denied the option of procuring power from the IOUs they have successfully done business with for many years.

(2) Municipal utilities will be forced to replace the power previously provided pursuant to PPAs with the IOUs by purchasing power in the "competitive" wholesale market. Municipal utilities would be forced to negotiate new PPAs and/or purchase power directly from the competitive market on a short-term (e.g., spot market, day-ahead) basis, exposing them to significant uncertainty and risk.

(3) Alternatively, municipal utilities may be forced to expand their capacity by constructing new generation facilities.

(4) An independent system operator ("ISO") will likely be necessary to develop, oversee, and administer the competitive wholesale electricity market. All generation will be required to participate in the competitive wholesale market overseen by an ISO, potentially including electricity generated by municipal utilities.

(5) The creation and administration of an ISO is costly. Based on experience in other deregulated markets, it's estimated the upfront costs to be between $100 million and $500 million and the on-going administrative and other costs to be $170 million to $228 million per year. Based on these estimates, the cost to JEA for creating and operating this ISO is estimated to

be between $6 million and $30 million in upfront costs as well as an additional $12 million per year in ongoing annual costs.

(6) Currently, the Florida Public Service Commission oversees the long-term, integrated Florida resource and reliability planning to ensure there is adequate electrical power generation provide for the needs of electric customers throughout the State of Florida. The companies that provide power in a restructured market would not be subject to this oversight, essentially doing away with long-term, integrated planning in Florida and exposing municipal utilities and their customers to substantial risk and potential costs.

(7) By limiting IOUs to the construction, operation, and repair of transmission and distribution systems ("T&D"), the Amendment would potentially result in IOUs selling this critical infrastructure relied upon to move power throughout the state, including to municipal utilities. This exposes municipal utilities to risk. At this point in time, it is not possible to estimate the cost to mitigate this risk.

(8) If the competitive retail market experiences capacity shortfalls or price spikes such as have occurred in other states with deregulated electricity markets, it is doubtful that municipal utilities would elect to participate in the competitive retail market. This has been the experience in Texas, where no municipal utilities (and only two electric cooperatives) have opted into retail competition to date.

(9) Deregulation has eroded operating reserve margins in Texas, which are currently down to 8%. This is substantially lower than the required reserve margins in Florida, which are set by the FPSC at 15% for municipal utilities and 20% for IOUs. As a result, customers would face a greater likelihood of service disruptions.

HOW WOULD PASSAGE OF THE AMENDMENT AFFECT JEA FINANCIALLY?

As JEA is itself a local government entity, it is uniquely positioned to provide the Committee with information directly related to the impact of the Amendment on its revenues. Specifically, JEA anticipates it would experience the following impacts:

- JEA's Brandy Branch Generating Station, Kennedy Generating Station, and Greenland Energy Center would likely participate in the competitive market administered and monitored by the newly-formed ISO. JEA has engaged a leading industry consultant to perform a study to more fully capture the estimated financial impact the Amendment would have on JEA.

- JEA and Florida Power & Light ("FPL") jointly (23.6% JEA/76.36% FPL) own the 846-MW Robert W. Scherer Unit 4 coal-fired generating unit and have ownership interests in certain common facilities at the Scherer Plant and an associated coal stockpile. The Amendment would force FPL to divest its ownership interests in and related to this plant, thereby forcing this sale on JEA. Depending upon the terms of the joint ownership, JEA may be faced with a new partner in this plant if one could be found. More likely, JEA would be forced to close the unit along with FPL. The estimated financial impact of this on JEA is in excess of $550 million.

- As indicated in the table presented below, JEA's transmission and interconnections are integrally tied to FPL. The Amendment may force FPL to divest its T&D investments, exposing JEA to uncertainty, risk, and costs.

FPL Station	**JEA station**	**Voltage**
Sampson	Switzerland	230 kV

Duval	Brandy Branch # 1	230 kV
Duval	Brandy Branch # 2	230 kV
Duval	Brandy Branch # 3	230 kV
Duval	Jax Heights	230 kV
Oneil	Nassau	138 kV
Oneil	Nassau via FPUstep	138 kV

- In addition, FPL and JEA are joint owners of two 500 kV transmission lines from Duval and the Duval substation. Under the Joint Ownership Agreement FPL owns 99% of the substation and JEA owns 99% of the lines. FPL operates and maintains the lines and substation. JEA reimburses FPL for the maintenance of the lines. The Amendment may force FPL to divest its ownership interest in these lines and substation, thus forcing JEA to fill this void and pay the resulting costs. Furthermore, if this transmission path gets subsumed into the ISO model, JEA stands to lose approximately $2.8 million annually in transmission revenue.

- Based on JEA's preliminary analysis and given the current price of natural gas and the generating fleet in Florida, JEA's Northside 1 & 2 power plants would likely not participate in the competitive market and would run less frequently and less efficiently than they do today. This would threaten the economic viability of the Northside Generating Station and potentially force JEA to shut down the plant entirely before the end of its useful life. Under this scenario, JEA may realize an estimated $431 million in stranded costs for the power plant.

- JEA participates in and benefits from the Florida Public Service Commission's long-term, integrated Florida resource and reliability planning. As discussed in JEA's 2018 Ten Year Site Plan:

> The Florida Public Service Commission (FPSC) is responsible for ensuring that Florida's electric utilities plan, develop, and maintain a coordinated electric power grid throughout the state. The FPSC must also ensure that electric system reliability and integrity is maintained, that adequate electricity at a reasonable cost is provided, and that plant additions are cost-effective. In order to carry out these responsibilities, the FPSC must have information sufficient to assure that an adequate, reliable, and cost-effective supply of electricity is planned and provided.
>
> The Ten-Year Site Plan (TYSP) provides information and data that will facilitate the FPSC's review. This TYSP provides information related to JEA's power supply strategy to adequately meet the forecasted needs of our customers for the planning period from January 1, 2018 to December 31, 2027. This power supply strategy maintains a balance of reliability, environmental stewardship, and low cost to the consumers.

The Amendment would essentially do away with this important, long-term, integrated planning in Florida, presenting significant risks and resulting costs.

In sum, under the Amendment, JEA would incur estimated up-front costs in the range of $987 million to $1.01 billion, in addition to estimated ongoing annual costs in the amount of $14.8 million. The high costs of the Amendment along with the destabilizing effects it would have on the wholesale and retail electricity markets and operating reserves would negatively impact municipal utilities, their customers, and the state as a whole.

Response to Requests from the FIEC to the IOUs from the February 21 FIEC Meeting

1. Rates Paid by Government Customers

During the February 21 meeting of the Financial Impact Estimating Conference, the Principals requested an overview of electricity rates paid by state and local government customers. Customers of Investor-Owned Utilities (IOUs) are classified based on the amount of electricity they consume. The IOUs do not offer unique rates for government customers. Approximately 90% of state and local government electricity usage is subject to small and medium commercial rates, with the remainder subject to large commercial, industrial and lighting rates. There are a number of different rates or tariffs paid by non-residential customers and these rate structures vary across the IOUs. The majority of the rates paid by non-residential customers include a variable $/kWh rate and an additional $/kW rate based on peak consumption.

For purposes of comparison, we have converted the rates paid by each customer group listed below to an average $/kWh rate. On average, commercial customers, and therefore state and local government customers, pay rates that are slightly lower than those of residential customers and slightly higher than those of industrial customers.

The table below summarizes these results:

	Average $/kWh[1]
State & Local Government Customers	$0.092
Residential Customers	$0.115
Small and Medium Commercial Customers	$0.089
Large Commercial and Industrial Customers	$0.068
Lighting	$0.187

(1) 2018 averages for FPL, Duke and TECO

2. Portion of Electricity Revenues Attributed to the Recovery of Generation Costs

During the February 21 meeting of the Financial Impact Estimating Conference, the Principals asked for more information regarding the portion of electricity rates that are attributed to generation (or production) costs, as opposed to other cost functions such as transmission and distribution. While this stratification is not itemized on the bill, a breakdown of revenue requirements by major function can be projected using cost of service studies that are performed by the utilities which categorize all of the utility's costs by function, e.g. production, transmission, distribution, etc. The analysis below relies on these studies and other publically filed documents to estimate the allocation of projected 2019 revenues to the various cost functions for the four Florida IOUs**. The proportion of revenues associated with production-related costs is estimated to be 70%, 71%, 74%, and 72% for Florida Power and Light (FPL), Duke Energy Florida (DEF), Tampa Electric Company (TECO), and Gulf Power, respectively.**

As regulated by the Florida Public Service Commission, the rates charged by IOUs are set to recover the costs of providing electric service, either through base rates or via pass-through clause adjustment rates. The majority of costs are associated with capital expenditures, depreciation, operations and maintenance, applicable taxes, and debt and equity financing, and are recovered through base rates that are set during rate cases that typically occur once every few years. Additional pass-through costs are charged through recovery clauses, for which rates are trued-up on an annual basis. These clauses allow for the following charges:

- Fuel charge, which reflects the cost of fuel required to provide each kilowatt-hour (kWh) of electricity;
- Capacity Cost Recovery Clause (CCRC) charge, reflecting the cost for purchasing electricity from non-utility owned resources as well as certain nuclear-related expenses;
- Environmental Cost Recovery Clause (ECRC) charge, reflecting the cost to comply with environmental laws and regulations; and
- Energy Conservation Cost Recovery (ECCR) charge, reflecting the cost of programs designed to reduce electric demand and consumption.

The following tables provide an analysis of the percentage of utility revenues that are attributed to each major cost function. In the example of FPL (Table 1), 57% of base revenues and 95% of clause revenues are allocated to the recovery of production-related costs. This equates to 70% of total revenues.

Table 1.

FPL ILLUSTRATIVE 2019 RETAIL REVENUE BY FUNCTION													
	Base Revenue ($000)[1]				Clauses ($000)[2]						2019 Total ($000)	
	2016 Rate MFR E-6b Proposed As-Filed Dkt. 20160021	%	Illustrative 2019 Base Revenue Allocation	%	Fuel	CCRC	ECRC	ECCR	Total	%	2019	%
Production	3,783,465	*57%*	3,771,731	*57%*	2,706,846	260,415	182,388		3,149,649	*95%*	6,921,380	*70%*
Transmission	555,414	*8%*	553,692	*8%*			1,438		1,438	*0%*	555,130	*6%*
Distribution	2,052,914	*31%*	2,046,548	*31%*			3,539	167,102	170,641	*5%*	2,217,189	*22%*
Customer	118,683	*2%*	118,315	*2%*					0	*0%*	118,315	*1%*
Lighting	88,091	*1%*	87,818	*1%*					0	*0%*	87,818	*1%*
Total	6,598,567	*100%*	6,578,103	*100%*	2,706,846	260,415	187,366	167,102	3,321,728	*100%*	9,899,831	*100%*

[1] Base revenue is illustrative and reflects retail base revenue for the 12 months beginning June 2019 as reflected in FPSC Docket 20180001 Exhibit TCC-2; Functional split uses same ratio as was reflected in MFR E-6b in Docket 20160021-EI

[2] Clause revenue and functional splits from Dockets 2018001-EI (Exhibits RBD-8 and RBD-9), 20180002-EG (Exhibit AS-2), and 2018007-EI (Exhibits RBD-4)

Table 2.

DEF ILLUSTRATIVE 2019 RETAIL REVENUE BY FUNCTION													
	Base Revenue ($000)[1]				Clauses ($000)[2]						2019 Total ($000)	
	2010 Rate MFR E-6b Proposed As-Filed Dkt. 20090079	%	Illustrative 2019 Base Revenue Allocation	%	Fuel	CCRC	ECRC	ECCR	Total	%	2019	%
Production	975,384	*50%*	1,110,318	*50%*	1,412,414	446,759	64,738		1,923,911	*94%*	3,034,228	*71%*
Transmission	198,540	*10%*	226,006	*10%*			287		287	*0%*	226,293	*5%*
Distribution	633,340	*33%*	720,955	*33%*			9	113,136	113,146	*6%*	834,101	*20%*
Customer	76,547	*4%*	87,136	*4%*					0	*0%*	87,136	*2%*
Lighting	60,592	*3%*	68,974	*3%*					0	*0%*	68,974	*2%*
Total	1,944,403	*100%*	2,213,389	*100%*	1,412,414	446,759	65,034	113,136	2,037,343	*100%*	4,250,732	*100%*

[1] Base revenue is illustrative and reflects retail base revenue for the 12 months beginning January 2019 as reflected in FPSC Docket 20180149 Exhibit MO-1; Functional split uses same ratio as was reflected in MFR E-6b in Docket 20090079-EI

[2] Clause revenue and functional splits from Dockets 2018001-EI (Exhibits CAM-3), 20180002-EG (Exhibit LJC-1P), and 2018007-EI (Exhibits CAM-5)

Table 3.

TECO ILLUSTRATIVE 2019 RETAIL REVENUE BY FUNCTION													
	Base Revenue ($000)[1]				Clauses ($000)						2019 Total ($000)	
	2013 Rate MFR E-6b Proposed As-Filed Dkt. 130040-EI	%	Illustrative 2019 Base Revenue Allocation	%	Fuel	CCRC	ECRC	ECCR	Total	%	2019	%
Production	615,933	59%	676,435	59%	519,093	16,893	54,980	53,534	644,501	100%	1,320,936	74%
Transmission	87,060	8%	95,612	8%					0	0%	95,612	5%
Distribution	214,160	21%	235,197	21%					0	0%	235,197	13%
Customer	40,858	4%	44,871	4%					0	0%	44,871	3%
Lighting	83,427	8%	91,622	8%					0	0%	91,622	5%
Total	1,041,438	100%	1,143,737	100%	519,093	16,893	54,980	53,534	644,501	100%	1,788,238	100%

[1] Base and clause revenues are illustrative and reflect forecasted retail revenues for the 12 months beginning January, 2019.
Base revenue functional split uses same ratio as was reflected in MFR E-6b in Docket 130040-EI.

Table 4.

GULF POWER ILLUSTRATIVE 2019 RETAIL REVENUE BY FUNCTION												
	Base Revenue ($000)[1]				Clauses ($000)[2]						2019 Total ($000)	
	2016 Rate MFR E-6b Proposed As-Filed Dkt. 20160021	%	2019 Base Revenue Allocation	%	Fuel	CCRC	ECRC	ECCR	Total	%	2019	%
Production	306,326	*46%*	276,915	*46%*	336,272	72,412	179,264		587,948	*97%*	864,863	*72%*
Transmission	96,422	*15%*	87,164	*15%*			1,414		1,414	*0%*	88,578	*7%*
Distribution	120,221	*18%*	108,678	*18%*			3,479	14,779	18,258	*3%*	126,936	*11%*
Customer	123,943	*19%*	112,043	*19%*					0	*0%*	112,043	*9%*
Lighting	15,766	*2%*	14,252	*2%*					0	*0%*	14,252	*1%*
Total	662,678	*100%*	599,053	*100%*	336,272	72,412	184,157	14,779	607,620	*100%*	1,206,673	*100%*

[1] Base revenue is illustrative and reflects retail base revenue as reflected in FPSC Docket 20180039-EI;
Functional split uses same ratio as was reflected in MFR E-6b in Docket 2016186-EI

[2] Clause revenue and functional splits from Dockets 2018001-EI, 20180002-EG, and 2018007-EI.

OWNERSHIP V. OPERATION OF TRANSMISSION AND DISTRIBUTION

In the February 21, 2019 meeting of the Financial Impact Estimating Conference ("FIEC") regarding the ballot measure *"Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice"* (the "Amendment"), questions were raised by the FIEC regarding the relevance of Investor-Owned Utilities' ("IOUs'") ownership of transmission and distribution ("T&D") infrastructure. As noted in other materials that have been presented, stranded costs for T&D have not been specifically quantified in the IOU's estimated financial impact.

The Amendment "limits investor-owned utilities to construction, operation and repair of electrical transmission and distribution systems." First, as has been noted in prior materials, this is unprecedented in the industry; no IOU has ever been forced to sell its entire T&D system as part of restructuring. Since there is no model where IOUs are limited to the construction, operation and repair of T&D, the proponents of the Amendment have no basis to suggest that there is a clear, risk-free path for establishing a market structure that separates the ownership and operation of this critical infrastructure.

The FIEC has asked for a short explanation of the primary differences between ownership and operation. Essentially, they are title, control and responsibility. In general terms, the owner of an asset holds title to that asset, controls the asset and is fully responsible for it, including financial and operational decisions. An operator is an agent of the owner and is responsible for operating the asset pursuant to a specific operating agreement which defines the operator's function and compensation. An operator has no stake in the assets, does not ultimately control decisions regarding the investment and long-term operation of the assets, has responsibility limited to day-to-day operations as set forth in the operating agreement and typically has very limited financial liability.

Today, IOUs own, operate, maintain, and invest in T&D to safely and reliably deliver electricity to their customers, all under the regulatory oversight of the Florida Public Service Commission ("FPSC"), the Federal Energy Regulatory Commission ("FERC"), and other agencies. IOUs' rates and allowed return on investments in T&D are set by the FPSC. The FPSC reviews IOUs' T&D system plans and capital investments. IOUs have an obligation to serve their retail customers and are responsible and accountable for reliable T&D service, including storm restoration, and acceptable customer service. IOUs invest in T&D on behalf of their customers to ensure safe, reliable service. In short, accountability and responsibility for operations are with the IOUs that also control investment decisions that are critical to reliability and service quality and subject to regulatory oversight.

By limiting IOUs to the construction, operation and repair of T&D, the Amendment would force IOUs to divest T&D. It is not clear who would step in as new owners given that they could not be "investor owned." Numerous issues would be created including:

- The Amendment does not identify who the owners of T&D assets would or could be; however, we know they cannot be *investor-owned* utilities. It's hard to imagine how a T&D system as large as the one currently owned and operated by the IOUs could be viable without private sources of capital. In fact, without access to investor-supplied capital, the only feasible new owners are public-power companies, such as cooperative and municipal power systems, or possibly a new legislatively created state agency, which have access to governmental sources of capital. These results will have financial impacts on state and/or local government.
- While the Amendment limits IOUs to constructing, operating and repairing T&D assets owned by others, it neither prohibits others from doing so nor guarantees that the IOUs who have safely and reliably operated these systems for decades will continue to do so. To assume that these obligations can simply be contracted out and would be performed at the same level of reliability is naïve at best.

- "Divorcing" day-to-day operation from investment decisions is suboptimal and could negatively influence reliability and service quality.
- While the newly-formed ISO, which is necessary to a functioning competitive wholesale electric market, would presumably be responsible for transmission system planning, distribution system planning would now be done on an owner-by-owner basis with no defined system-wide planning and if a system-wide planning process for distribution could be implemented, the presence of potentially dozens of new T&D owners would create the need for extensive coordination, increasing costs.
- If the result is dozens of new owners of T&D, it means the loss of economies of scale, duplication of functions, the creation of incremental, and unnecessary cost.
- The Amendment is silent on how operators of T&D will be compensated. Operators will require a reasonable profit opportunity, including a return on their human capital investment; operators cannot be expected to provide service without the opportunity to do so profitably. Costs and customer rates will increase as a consequence of this additional profit component of the total cost of serving customers.

STANDARDS FOR ESTIMATING FINANCIAL IMPACTS

INTRODUCTION

In the February 21, 2019 meeting of the Financial Impact Estimating Conference ("FIEC") regarding the ballot measure *"Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice"* (the "Amendment"), questions were raised by the FIEC regarding the "probable" financial impact of the Amendment on state and local government. The purpose of this document is to provide a summary of the analysis that we believe clearly warrants findings of significant negative financial impact to state and local government. On February 20, 2019, the four major investor-owned utilities ("IOUs")[1] submitted a report that detailed extensive analyses of the Amendment's impacts. In aggregate, for those impacts that the report has quantified, it is estimated that state and local governments will incur at least $9.5 billion in negative financial impacts over ten years. As noted in the IOUs' report and during the IOUs' presentation, this is a conservative estimate, both because of the conservative approach taken in the case of each element and because many impacts, though likely if not certain, have not yet been quantified for purposes of this process.

ESTIMATED FINANCIAL IMPACTS OF THE AMENDMENT ARE PROBABLE

Table 1 assesses the estimated increases in upfront costs to state and local government which would result if the Amendment is approved.

Table 1: Assessment of Estimated Upfront Cost of the Amendment ($ million)

	Estimate	Ten Year Minimum	Assessment
Generation Stranded Costs	$1,100 - $1,400	$1,100	The forced divestiture of generating assets in other states that restructured their electricity markets created substantial stranded costs. Recent sales of U.S. power plants were at values substantially lower than the net book value of those plants. In every state where stranded costs were created, IOUs recovered those costs from customers through electricity rates, such as through a charge or recovery clause mechanism on customer's bills. This was necessary to avoid a Constitutionally-impermissible "taking" of private property without just compensation. Some form of stranded cost recovery will be necessary to implement this Amendment, because it compels divestiture of IOU assets. Applying these facts to the IOU generating plants only and allocating a conservative estimate of the compensable stranded costs to state and local government on the basis of their electricity consumption will result in costs of at least $1.1 billion to state and local government.

[1] Duke Energy Florida, Florida Power & Light Company, Gulf Power Company, and Tampa Electric Company.

	Estimate	**Ten Year Minimum**	**Assessment**
Creation of Competitive Wholesale Market	$11 - $55	$11	The Amendment requires fully competitive wholesale and retail electricity markets. All states that have restructured are part of either an ISO or a regional transmission organization ("RTO"). While different ISOs and RTOs may have different designs, they all provide the same basic development, oversight and administration of a competitive wholesale electric market. The creation of ISOs and RTOs have cost hundreds of millions of dollars. Applying these facts to Florida and allocating the costs to state and local government on the basis of their electricity consumption results in competitive wholesale market implementation state and local government will pay for of no less than $11 million.
Litigation Costs	$150 - $300	$150	It is clear from the FIEC meetings that the Amendment is poorly drafted and creates constitutional rights to things the Legislature may be unable to deliver. As complex and controversial as the implementing legislation will be, and considering that certain rights will be constitutionally enshrined, litigation is inevitable. It is highly probably that the state will spend hundreds of millions of dollars on lawyers and consultants over multiple years as government attempts to implement this Amendment.
Total Upfront Cost	**$1,261 - $1,755**	**$1,261**	

Table 2 assesses the estimated decreases in annual revenues and increases in annual costs to state and local government which would result if the Amendment is approved.

Table 2: Assessment of Estimated Annual On-Going Costs of the Amendment ($ million)

	Annual Estimate	**Ten Year Minimum**	**Assessment**
Franchise Fees	$679	$6,790	$679 million is the actual amount of franchise fees paid by IOUs in 2018. These fees are paid pursuant to contracts between municipalities and IOUs. Prohibiting exclusive franchises and prohibiting IOUs from owning T&D would result in the termination of the franchise agreements, thus ceasing franchise fee payments. While it is possible that the municipalities may seek to impose different fees on other parties or to increase property or other taxes to offset the loss of franchise fees, their ability to do so is unclear. Further, the financial impact statement should identify the probable loss of revenues to local government by observing the elimination of franchise agreements so as to put the voter on notice as to the size of the financial deficit that municipalities will need to try to address through other taxes and fees in order to preserve the existing level of services.
Property Taxes	$129.4 - $173.8	$1,294	Property taxes are assessed on the net book value of utility property. The Amendment would force IOUs to divest generation and transmission and distribution ("T&D"). The IOUs presented extensive research and analysis of generation stranded costs that would be created by this divestiture. There is no credible scenario where stranded costs would not be created. When utility property is revalued, its tax basis will decrease and so will property taxes. These estimates are conservative and assume no tax loss for T&D.
Independent System Operator ("ISO") Administrative Costs	$18.7 - $25.1	$187	There will be on-going, annual costs to administer the competitive wholesale market required by the Amendment. Administering an ISO will cost money and that cost will ultimately be reflected in the rates customers pay. Actual annual operating budgets to administer other single-state ISOs are $170 million (ERCOT) to $228 million (NYISO). State and local government as customers will pay their proportionate share of these costs.
Total Annual Cost	**$827 – $878**	**$8,271**	
Total Ten Year Minimum		**$9,532**	

While not quantified in our analysis, there are numerous other costs that would occur post-restructuring, meaning the results above are the minimum impact to Florida and state and local governments. Those costs include:

- Additional costs to state and local governments related to implementation and ongoing administrative costs under restructuring.
- Stranded costs beyond those quantified above, including those related to T&D assets, natural gas pipeline contracts, PPAs, regulatory assets, and other stranded assets.
- Additional risks related to declines in other state and local taxes, such as gross receipts tax and municipal public service tax
- Costs to the IOUs for the early retirement of debt related to their infrastructure.
- The costs associated with any additional degree of state involvement as an operational or financial backstop to ensure the constitutionally guaranteed rights of this Amendment or to address the political or practical realities of any market failures.
- Costs to the state economy due to lost productivity and disruption caused by the dismantling of the state's reliable and low-cost electricity system during the uncertain transition to the new competitive market, including lost economic development opportunities.

KEY CONCLUSIONS

These estimates of the potential impacts of the Amendment on revenues and/or costs of state and local government are based on specific research and analysis, including actual costs incurred in states which have restructured their electricity markets. There is no credible scenario where the proposed Amendment will not be financially negative to state and local government. Even if one were to consider only the impact on taxes in a single year, the proposed Amendment would still reduce revenues to state and local government by hundreds of millions of dollars. Very conservatively considering other revenue and cost impacts of the proposed Amendment, results in quantifiable stranded costs in the billions of dollars. We believe that the data indicates that these negative financial impacts on state and local government more than satisfy any reasonable interpretation of the term "probable."

MEMORANDUM

TO:	Financial Impact Estimating Conference
FROM:	Stuart Singer, Boies Schiller Flexner LLP
DATE:	March 1, 2019
SUBJECT:	Financial Impact Analysis and Florida Proposed Energy Market Initiative

INTRODUCTION

The proposed amendment to the Florida Constitution titled, "Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice" (referred to as the "Amendment" in this memorandum), would impose substantial costs on the state and municipal governments of Florida, and those costs should be disclosed in a financial impact statement. As discussed in this memo, the Amendment entirely deprives "investor-owned utilities" (referred to as "IOUs") of their property—requiring them to sell off or dispose their generation, transmission, and distribution facilities, equipment, and plants—and thus imposes a "taking" of private property. Under the U.S. Constitution, the State will be required to pay "just compensation" for this taking, an amount that will likely cost billions of dollars. Additional costs of the Amendment would include litigation expenses and diminished tax revenue, addressed in Section II below.

All these costs are properly disclosed because they are inevitable, significant, and fall squarely on the State government implementing this Amendment and the associated taking. Disclosure is appropriate, "so that an educated decision may be made with regard to [the] proposed amendment." *Advisory Opinion to Attorney Gen. re Standards For Establishing Legislative Dist. Boundaries*, 2 So. 3d 161, 164 (Fla. 2009).

DISCUSSION

I. The Amendment Will Require the State to Pay "Just Compensation" for a Taking of Property.

The US Constitution prohibits taking property without providing "just compensation" to the owner. U.S. Const. amend. V. Courts have recognized two general types of taking: a *per se* taking, where the government occupies, destroys, or otherwise "ousts" the owner from property, and a "regulatory" taking, where the government leaves property where it is but imposes such burdensome regulations on the property that it loses much of its real value. *See Horne v. Dep't of Agric.*, 135 S. Ct. 2419, 2426 (2015); *Lucas v. South Carolina Coastal Council*, 505 U.S. 1003, 1014 (1992).

The Amendment is a taking under either standard. As discussed below, the Amendment creates a *per se* taking by physically depriving IOUs of their property—namely, transmission, generation, and distribution equipment. Even if this were not a *per se* taking, the total deprivation of ownership rights imposed by the Amendment would constitute a regulatory taking. Either way, this taking would require the State to pay just compensation, which should be disclosed in the financial impact statement. Documents before the Conference show that this amount could exceed $30 billion.

a. By physically depriving investor owned utilities of its facilities, the Amendment is a *per se* taking.

The proposed Amendment likely imposes a *per se* taking, because it requires IOUs to give up all ownership of their generation, transmission, and distribution equipment. In *Horne*, for example, the U.S. Supreme Court found a *per se* taking where the government required raisin growers to turn over a portion of their crops to a committee, which would either sell the raisins (and return a portion of the proceeds), give them away, or discard them as the committee saw fit. *Horne*, 135 S. Ct. at 2428. The Supreme Court considered this "a clear physical taking," in part because "[r]aisin growers subject to the reserve requirement thus lose the entire 'bundle' of property rights in the appropriated raisins—'the rights to possess, use and dispose of' them." *Id.* (citation omitted; quoting *Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419, 435 (1982)). Other courts have found a forced sale of property to constitute a taking without considering any of the balancing factors applied in the regulatory-takings analysis. *Dore v. United States*, 97 F. Supp. 239, 242 (Ct. Cl. 1951) ("When, as here, the United States exercises its authority to order delivery and in its sovereign capacity forces the 'sale' of property to it for public use there is, in our opinion, a 'taking' and just compensation must be made."); *Armendariz v. Penman*, 75 F.3d 1311, 1321 (9th Cir. 1996) (scheme "to deprive the plaintiffs of their property, either by forced sale … or by causing the plaintiffs to lose their properties by foreclosure" would constitute a taking), *abrogated on other grounds by Lingle v. Chevron U.S.A. Inc.*, 544 U.S. 528, 532 (2005).

Under the proposed Amendment, IOUs would be precluded from owning generation, transmission, and distribution equipment, and they would "thus lose the entire 'bundle' of property rights" in that equipment. *Horne*, 135 S. Ct. at 2428. This "equivalent of a 'practical ouster of [the owner's] possession'" amounts to a *per se* taking, *Lucas*, 505 U.S. at 1014 (quoting *Transp. Co. v. Chicago*, 99 U.S. 635, 642 (1879)), because the utilities are forced to entirely abandon their ownership of the physical generation, transmission, or distribution facilities.

The Amendment effects a *per se* taking even though it leaves IOUs with the ability to sell their facilities. *Dore*, 97 F. Supp. at 579 – 80 (finding a taking where farmers were forced to sell their rice). In *Horne*, the Supreme Court rejected the idea that because farmers retained the right to net proceeds from any sale of the confiscated raisins, "they retain the most important property interest in the reserve raisins, so there is no taking in the first place." *Id.* at 2429. The Court explained that "when there has been a physical appropriation, 'we do not ask ... whether it deprives the owner of all economically valuable use' of the item taken." *Id.* (quoting *Tahoe-Sierra Pres. Council, Inc. v. Tahoe Reg'l Planning Agency*, 535 U.S. 302, 323 (2002)). Because IOUs will be physically ousted from property they currently own, there is a taking even though the utilities may retain a fleeting and theoretical right to sell the assets before the Amendment and implementing laws go into effect. Analogously, a law prohibiting natural persons from owning homes in the state of Florida would likely constitute a *per se* taking even if current homeowners had the ability to sell off their homes before being evicted from their property. *See Armendariz*, 75 at 1321.

It does not matter that the Amendment does not require the *government* to take long-term ownership of IOUs' equipment. The takings analysis is measured by the loss to the property owner, not the gain to the new recipient. *See, e.g.*, *United States v. Gen. Motors Corp.*, 323 U.S. 373, 378 (1945) ("The courts have held that the deprivation of the former owner rather than the accretion of a right or interest to the sovereign constitutes the taking. Governmental action short of acquisition of title or occupancy has been held, if its effects are so complete as to deprive the owner of all or most of his interest in the subject matter, to amount to a taking."). Thus, courts have found a *per se* taking when the government caused property to be flooded, even though the government did not actually possess that property. *See, e.g.*, *United States v. Welch*, 217 U.S. 333, 338 (1910).

By completely "ousting" all IOUs from their property interests in generation, transmission, and distribution facilities, the Amendment effects a *per se* taking of the utilities' property, for which the State will have to pay just compensation.

b. Even if there is no *per se* taking, there is a regulatory taking.

Even if a court found that forcing utilities to sell off their own property was not a *per se* taking, it would still conclude that the Amendment effects a regulatory taking. A regulatory taking happens when a "regulation goes too far" in limiting an owner's property rights. *Penn. Coal Co. v. Mahon*, 260 U.S. 393, 415 (1922). This can be shown in two ways: first, if the regulation "denies all economically beneficial or productive use" of the property, or second, if the regulation fails a three-part balancing test that considers "(1) the economic impact of the regulation on the claimant; (2) the extent to which the regulation has interfered with distinct investment-backed expectations; and (3) the character of the governmental action." *Murr v. Wisconsin*, 137 S. Ct. 1933, (2017) (quoting *Palazzolo v. Rhode Island,* 533 U.S. 606, 617, 121 S.Ct. 2448, 150 L.Ed.2d 592 (2001)).

The Amendment fails under either test. First, as noted above, the Amendment would deny "all economically beneficial or productive use" of the facilities to any investor-owned utility, since the utility would be entirely prohibited from owning such a facility. As a result of the Amendment, IOUs would be prohibited from putting their property to *any* "economically beneficial or productive use," except for the theoretical possibility of selling the facilities to as-yet unidentified, non-investor-owned purchasers.

Similarly, under the three-part balancing test, there is no question that the regulation "goes too far." First, the "economic impact" is enormous, requiring total divestiture of the utilities' significant generation, transmission, and distribution facilities, all worth billions of dollars—in a market demonstrably unable to pay true value for these assets. *See* "Support for FIEC Financial Impact Statement" (referred to as the "Support Statement"), at 27 – 31. Second, the Amendment upends "investment-backed expectations" by requiring divestiture of property that utilities have long owned and in which they have invested significant, unrecoverable amounts. *See id.* at 9, 27 – 31. Third, the "character of the governmental action,"—coerced sale of valuable property—only confirms that this is a taking rather than a mere regulation of property. *See, e.g.*, *Duncan v. Becerra*, 742 Fed. Appx. 218, 222 & n.3 (9th Cir. 2018) (affirming that taking occurred where state forced owners of large-capacity magazines to choose between selling the magazines to firearms dealers, surrendering them to the government for destruction, or removing them from the state, because it would "fundamentally 'deprive Plaintiffs not just of the *use* of their property, but of *possession*, one of the most essential sticks in the bundle of property rights'"); *Amen v. City of Dearborn*, 718 F.2d 789, 797 (6th Cir. 1983) (finding taking where city "chose not to invoke its condemnation powers, but, rather, elected to engage in a deliberate course of conduct to force the sale of private property at reduced value").

Indeed, far less drastic limitations on a utility's use of its assets have been found to constitute a taking. For example, a regulatory taking occurs when a state sets utility rates that are too low: "The guiding principle has been that the Constitution protects utilities from being limited to a charge for their property serving the public which is so 'unjust' as to be confiscatory." *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 307-08 (1989); *see also Bluefield Waterworks & Improvement Co. v Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-93 (1923). Other states that have engaged in deregulation—but without the drastic step of forcing utilities to divest generation, transmission, and distribution facilities—have similarly faced challenges under the Takings Clause, based on the contention that the post-deregulation market lacked adequate measures to allow the utilities to recover certain stranded costs. *See, e.g.*, *Pacific Gas & Elec. Co. v. Lynch*, 216 F. Supp. 2d 1016, 1048 (N.D. Cal. 2002) (considering Takings claim challenging post-deregulation rate freeze as inadequate to recover stranded investment costs).

The Amendment goes well beyond merely setting a utility's rates too low, or interfering with recovery of stranded costs: it literally deprives the IOUs of all ownership of generation, transmission, and distribution facilities. Considering the severe economic impact of the Amendment, the extent to which the Amendment will interfere with actual investment and investment-backed expectations in the property, and the blatantly confiscatory character of the governmental action, the Amendment will be considered a taking even if the regulatory, rather than *per se*, tests apply.

Thus, under any standard, the Amendment imposes a taking, and the State will be required to pay "just compensation."

BSF

c. The financial impact statement must disclose the duty to pay just compensation, because the duty falls on the State government.

As described above, the Amendment imposes a taking, and thus the U.S. Constitution will require the State to pay "just compensation." U.S. Const. amend. V. The duty to pay just compensation for a taking falls on the State government, and thus the costs should be disclosed in a financial impact statement. *See, e.g.*, *City of Monterey v. Del Monte Dunes at Monterey, Ltd.*, 526 U.S. 687, 710 (1999) (explaining that plaintiff was entitled to monetary remedy against state, under § 1983, if the state failed to provide sufficient "compensatory remedy" for regulatory taking); *Williamson Cnty. Reg'l Planning Comm'n v. Hamilton Bank of Johnson City*, 473 U.S. 172, 194 – 195 (1985) (explaining that government must ensure that "a 'reasonable, certain and adequate provision for obtaining compensation' exist at the time of the taking" (quoting *Regional Rail Reorganization Act Cases*, 419 U.S. 102, 124–125 (1974))).

Allowing IOUs to sell their generation, transmission, and distribution facilities will not be sufficient "just compensation" under the Fifth Amendment. Just compensation "means the full monetary equivalent of the property taken." *United States v. Reynolds*, 397 U.S. 14, 16 (1970). The Supreme Court has recognized that market values may fail to provide just compensation in some instances, especially where the taking itself depresses the market. *See id.*

Here, any market for these facilities is purely speculative and, in practice, unlikely to materialize, as experience in other states has shown. *E.g.*, Support Statement at 28 – 31. Assuming that private, non-investor-owned purchasers can be found (and thus the State does not take on the added cost of purchasing the assets itself), the market will be depressed by the Amendment itself, which will create a "fire sale" while prohibiting the most likely purchasers—investment-owned utilities—from making offers to buy the equipment. *See* Support Statement at 27; *Amen v. City of Dearborn*, 718 F.2d 789, 799 – 800 (6th Cir. 1983) (rejecting sale price as best measure of just compensation where government's conduct in forcing plaintiffs to sell their home caused depressed market for the assets); *Duncan v. Becerra*, 265 F. Supp. 3d 1106, 1138 (S.D. Cal. 2017) (finding that state law forcing private owners to sell or dispose magazines would drive "market value" of those magazines to "near zero"), *aff'd*, 742 Fed. Appx. 218 (9th Cir. 2018).

At least three factors will depress prices even if any purchasers can be found. First, the Amendment creates uneven bargaining conditions because prospective purchasers know that IOUs are required to sell off their assets (and thus cannot refuse low offers).

Support Statement at 27. Second, because the Amendment completely upends the Florida electricity markets in addition to requiring divestiture, any purchase price will be reduced to account for the purchasers' risk in entering a new, unproven Florida marketplace. *Id.* Third, several investments that were proper and prudent under Florida's existing structure may be undervalued in an open-market purchase, such as investments targeting environmental goals or fuel diversity. *Id.*

The documents before the Conference quantify the value of IOUs' generation assets that likely cannot be recovered by selling the generators in a post-Amendment market. These are referred to as "stranded costs," where "the market value of utility assets in a restructured market is less than the value on the utilities' books." Support Statement at 27. Drawing on a "wealth of experience" from other states, the Support Statement indicates that the difference between the true value of generation assets and the value that could be expected in the post-Amendment market could be between $9.8 to $12.3 billion. Support Statement at 27 – 31. Under the Fifth Amendment, the State would have to make up this difference even if the IOUs are permitted to sell their assets. *See Amen*, 718 F.2d at 799 – 800. The Statement further indicates that the value of the transmission and distribution systems exceeds $24.3 billion, and that a "substantial portion of this" would likely become "stranded" in the post-Amendment market. Support Statement at 9. Thus, the total stranded costs from generation, transmission, and distribution equipment could easily exceed $30 billion.

These costs should be disclosed in the Financial Impact Statement. Indeed, at least one other state has included the cost of "takings" payments in the financial impact statement related to a proposed ballot measure. The Colorado Supreme Court affirmed a financial impact statement that stated that "If the courts were to hold this measure to be a 'taking' of private property, the State could be obligated to pay the owners of the stream beds just compensation, and ***the fiscal impact upon the State could be substantial.***" *Matter of Title, Ballot Title & Submission Clause, & Summary Approved on Apr. 6, 1994, for Proposed Initiated Constitutional Amendment Concerning Fair Fishing*, 877 P.2d 1355, 1359 (Colo. 1994) (emphasis added).

d. Even if the price could be passed on to Florida ratepayers, the cost of "just compensation" for the takings is a cost to the state that must be included in the Financial Impact Statement.

The Support Statement indicates that "[t]he state of Florida would have to either fund the compensation for the billions of dollars of this property 'taken' as a result of the Amendment or pass those costs on to current customers (including state and local government customers) through a non-bypassable recovery charge on electric bills as other states have elected to do." Support Statement at 27. The Support Statement provides conservative estimates of the total cost to the government by excluding the portions of "stranded costs" that might be passed on to non-government ratepayers through this statewide "rate surcharge." *E.g.*, Support Statement at 9. [1] But even if the government uses a statewide surcharge to pass the costs of just compensation on to Florida citizens, the full amount of those costs is still properly disclosed in the Financial Impact Statement—just like any other cost that might be paid for by increasing taxes. Thus, the Financial Impact Statement should disclose the full amount of just-compensation cost to the state, ranging from $9.8 billion to over $30 billion, without a discount for whatever rate surcharge might be imposed to pay for it.

Regardless of whether the state were able to avoid directly paying remuneration for the taking of investor-owned property brought about by the proposed amendment and were instead able to "pass" that cost on to ratepayers, the state is still responsible for paying "just compensation" for the takings effected by the Amendment. In other words, even if the state enacts a tax to fund that increased cost, the increased cost must still be disclosed. As explained, the "stranded costs" for which IOUs must be compensated may be expected to total between **$9.8 to $12.3 billion** for generation resources alone, and up to an additional $24.3 billion for transmission and distribution assets as well. *See* Support Statement at 9, 29-31, 56.

The proposed amendment, by its plain language, contains no mechanism by which to pass "stranded costs" or other takings-related costs on to ratepayers and/or taxpayers, and does not require or even suggest legislation to that effect. However, there is no need for the Conference to speculate regarding the mechanism by which the state would fund the cost of paying just compensation for the takings effected by the Amendment, because full the cost of the takings must ultimately be paid by the state. The cost to the state of paying "just compensation" will be the same regardless of how the state funds these payments. And this cost would still constitute in a significant and quantifiable "increase . . . in . . . costs to state or local governments resulting from the

[1] The Support Statement's estimates of $1.1 billion to $1.4 billion, at 9, indicate only the costs that can be expected to be directly born by the state if the state attempts to pass the bulk of the costs on to ratepayers.

proposed initiative," Fla. Stat. § 100.371(5)(a), that should be quantified and discussed in the Financial Impact Statement.

Moreover, under the regime contemplated by the Amendment, the state may not regulate the price of wholesale or retail electricity. The only conceivable way that the state could pass the costs of "just compensation" for the taking onto the ratepayers, thus allowing IOUs to recover their "stranded costs" and other property losses resulting from the Amendment, would be to impose a surcharge or surtax for that purpose on top of the market-priced rates. But this tax would simply be a mechanism to fund the state's obligations to compensate the IOUs for their taken property. Like any cost to the State that would ultimately be funded by taxpayers, the State's ability to pass these costs on to the populace at large does not change the obligation to disclose this cost in the Financial Impact Statement.

The Financial Impact Statement must describe "the estimated ***increase or decrease*** in ***any revenues or costs*** to state or local governments resulting from the proposed initiative," Fla. Stat. § 100.371(5)(a) (emphasis added); the Financial Impact Statement must thus describe an increase in both revenues and costs. *See also In re Advisory Opinion to Atty. Gen. re Use of Marijuana for Debilitating Med. Conditions*, 181 So. 3d 471, 476 (Fla. 2015) (approving Financial Impact Statement noting that "Fees may offset some of the regulatory costs"); *In re Advisory Opinion to Atty. Gen. re Limits or Prevents Barriers to Local Solar Elec. Supply*, 177 So. 3d 235, 241 (Fla. 2015) (approving Financial Impact Statement noting that "State and local governments will incur additional costs, which will likely be minimal and partially offset by fees").

II. The Initiative Would Result In Other Costs To Government That Must Be Discussed In The Financial Impact Statement.

In addition, there are other costs that must be discussed and quantified in the Financial Impact Statement as well. The Financial Impact Statement must discuss "the estimated increase or decrease in ***any*** revenues or costs to state or local governments resulting from the proposed initiative." Fla. Stat. § 100.371(5)(a) (emphasis added).

For example, the initiative will result in increased litigation costs, including resolution of all of the takings questions associated with the initiative and other questions related to the divestiture and sale of existing assets. Indeed, increased litigation costs are likely at every step of the ballot measure's implementation. As explained, the Amendment will immediately spark takings litigation. Other litigation will soon follow. For one, the Amendment grants all Floridians standing to seek judicial relief if they feel they have not received "meaningful choices among a wider variety of competing electricity providers." Given the breadth of this right, it is likely to risk significant and continuous litigation costs. More than that, if the Amendment were implemented, high litigation costs would become the norm, as "competitors" in the new market litigate capacity design and market manipulation claims, which often require state and local government participation. These costs may be especially high in the context of takings litigation, given that the state must generally pay certain attorneys' fees for successful takings claims. *See* Fla. Stat. § 73.092. Thus, litigation costs are expected to range from $150 to $300 million. *See* Support Statement at 10, 27 & n.23, 73-75.

Such increased litigation costs are properly included in the Financial Impact Statement. The Florida Supreme Court approved a Financial Impact Statement that noted that "state government and state courts may incur additional costs if litigation increases beyond the number or complexity of cases which would have occurred in the amendment's absence." *Advisory Opinion to Attorney Gen. re Standards For Establishing Legislative Dist. Boundaries (FIS)*, 24 So. 3d 1198, 1199 (Fla. 2009). Additionally, the Supreme Court of Colorado approved a financial impact statement acknowledging litigation costs, noting that "the Board's statement regarding litigation costs is adequate: 'This measure could have a fiscal impact at the state level from litigation costs incurred in defending the measure against legal challenges. . . .'" *Matter of Title, Ballot Title & Submission Clause, & Summary for 1997-1998 No. 105 (Payments by Conservation Dist. to Pub. Sch. Fund & Sch. Districts)*, 961 P.2d 1092, 1097 (Colo. 1998), as modified on denial of reh'g (Aug. 10, 1998).

Similarly, the initiative would also have the effect of diminishing tax revenue and franchise fees. The amendment will prevent generators and other assets from being owned by IOUs, and due to the lack of potential buyers and other uncertainties, assets may have to be divested at "fire sale" prices (if they could be purchased at all), which would have the effect of dramatically lowering the tax base assessment on those assets, costing the state $129 to $174 million in annual property tax revenues. *See* Support Statement at 10, 27, 31-33, 56-67. Similarly, since the Amendment will eliminate the exclusive-use franchises that IOUs currently occupy, they would no longer be required to pay franchise fees to localities, and these lost franchise fees could be in excess of $679 million per year. *See id.* at 33-34. The financial impact statement should discuss these likely revenue shortfalls resulting from the diminished tax base and lost franchise fees.

For example, the Florida Supreme Court upheld a financial impact statement that noted that "the amendment will result in decreased state and local government revenues overall." *In re Advisory Opinion to Atty. Gen. re Limits or Prevents Barriers to Local Solar Elec. Supply*, 177 So. 3d 235, 241 (Fla. 2015). Likewise, the Court upheld a statement noting that "The amendment will reduce annual total school, county, municipal and special district property tax revenues by at least $6 billion . . ." *Advisory Opinion to Attorney Gen. re 1.35% Prop. Tax Cap, Unless Voter Approved*, 2 So. 3d 968, 976 (Fla. 2009). Similarly, the Colorado Supreme Court approved of a financial impact statement that cautioned that it would create a diminished tax base. *See Matter of Proposed Initiated Constitutional Amendment Concerning Ltd. Gaming in City of Antonito*, 873 P.2d 733, 743 (Colo. 1994) ("In its statement, the Board recognized that the tax base would be smaller, possibly producing a tax revenue loss.").

As explained in the Support Statement, the Committee must address several additional costs brought about by the Amendment. The Amendment would entail significant start-up costs, including the development of a wholesale market and independent system operators ("ISOs") to oversee that market, as well as consumer education and other costs, which in total would cost between $31 and $71 million. *See* Support Statement at 10, 24-27. And the annual maintenance cost to the state of market-operating organizations would be an additional $18 to $25 million per year. *Id.* at 10, 59. These direct costs to the state stemming from the Amendment must be included in the financial impact statement.

The Cost of Deregulation Across the States

Energy Fairness appreciates the opportunity to address you during the Financial Impact Estimating Conference process. By now, you have received voluminous testimony and research regarding the potential impacts of electricity deregulation in Florida. We have shared our concerns with respect to a variety of issues: consumer costs, deceptive practices, reliability problems and deregulation's documented failures in other states.

As you conclude your work and prepare a financial impact statement, we wanted to call attention to specific costs borne by states after establishing a deregulated electricity market. Multiple organizations, in addition to our own, have presented estimates of close to or exceeding ***$1 billion*** in annual losses to Florida's state and local governments should this proposed amendment pass.

We would ask you to look at costs to state governments as well as losses to revenue sources such as ad valorem property taxes, franchise fees and gross receipt taxes. Below, you will find a short summary of costs incurred in other states that would likely also be incurred in Florida under this amendment, such as consumer education, public assistance, and operational costs. Much of this data can be found in your second FIEC notebook online from research compiled by EDR as well as presentations by our organization and others.

In most cases, these costs add up to hundreds of millions of dollars annually. Please consider these costs to state government as you draft your financial impact statement for the proposed deregulation amendment.

Respectfully,

Paul Griffin
Energy Fairness

Costs to create and operate an ISO/RTO:

Energy Fairness' FTI study[1] on the costs of deregulation submitted to the FIEC in February 2019 found the start-up and operating costs for various ISO/RTO's across the country to be substantial.

ISO/RTO	State(s)	Start-Up Costs	Operational Costs
CAISO	California	$396 million	$196 million
ISO-NE	New England	$65 million	$184 million
NYISO	New York	$104 million	$143 million
PJM	PA,MD, NJ	$188 million	$308 million
MISO	Midwest	$189 million	$218 million

Additionally, the 2019-2020 biennial budget request for Texas' ERCOT showed a $228 million operating budget for Fiscal Year 2020.

In 2004, FERC estimated these costs to be between $38 million and $117 million.[2] Florida's costs would doubtless be on the high end of the range or exceed it. As the Charles River Associates Report calculated, that estimate would be between $50 and $155 million in today's dollars.[3]

With specific respect to Florida, a December 2005 GridFlorida estimate for the creation of a Florida RTO's start-up costs estimated a negative $704 million fiscal impact for a Day-1 operation and a negative $1.25 billion fiscal impact for a Delayed Day-2 operation.[4] Those costs would be even higher when adjusted for inflation.

Public Assistance Funds established by other states following deregulation:

A common factor between states that adopted energy deregulation was the establishment of public benefits assistance funds for low-income residents. We believe that history, in addition to the proposed amendment's requirement for the Legislature to "implement language that entitles electricity customers to purchase competitively priced electricity," would mean the State of Florida would establish a similar program for its low-income residents. Such a program would likely cost tens or even hundreds of millions of dollars, given the high number of low-income residents in the state.

Many of our findings are for household and individual assistance programs created by the deregulation legislation passed by other states and can be found in the 2005 Report on Congress on Competition in Wholesale and Retail Markets for Electric Energy report included in your FIEC binder. Other figures are noted as applicable.

[1] FTI, "Potential Impacts of Initiative 18-10 on State and Local Revenues in Florida," February 2019
[2] https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf?csrt=10019579922585194549
[3] Charles River Associates, "Florida Electricity Markets Restructuring Ballot Initiative: Potential Financial Impact to Florida State and Local Governments," February 2019
[4] Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy (2005), pg. 133

California:

Deregulation legislation passed in California authorized more than ***$540 million*** to be collected over a four year period by a non-bypassable wires charge for low-income assistance, energy efficiency and R&D programs.[5]

Illinois:

Illinois' restructuring act created three public benefits funds worth ***$75 million*** and originally slated to expire in 2006.[6]

Maryland:

Maryland's restructuring act created a ***$34 million*** per year universal service fund.[7]

Massachusetts:

The 1997 Massachusetts law created ***$156 million*** in public benefits programs.[8]

New Jersey:

New Jersey's deregulation law authorized ***$10 million*** for low income assistance.[9]

New York:

$22 million in low income assistance was authorized by New York's law.[10]

Pennsylvania:

Pennsylvania authorized ***$85 million*** in low income assistance in their deregulation law.[11]

Texas:

Texas' law authorized ***$166 million*** in low income assistance.[12]

[5] Florida PSC website - http://www.psc.state.fl.us/Publications/ElectricRestructuringDetails
[6] Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy (2005), pg. 142
[7] Ibid, pg. 146
[8] Ibid, pg. 150
[9] Ibid, pg. 155
[10] Ibid, pg. 161
[11] Ibig, pg. 166
[12] Ibid, pg. 174

Public education efforts in other states:

Educating Floridians about their new electricity regulation system would likely be required by the passage of this amendment and result in an appropriation of state funds. Several states' educational expenses are listed below.

Maryland:

Maryland's deregulation law included a ***$6 million*** appropriation of state funds for public education.[13]

Nevada:

Although Nevadans rejected a deregulation constitutional amendment in 2018, their Public Utilities Commission examined potential costs to the state and found at least ***$10 million*** would be needed for public education and outreach.[14]

Pennsylvania:

The same PUCN report found Pennsylvania spent ***$15.5 million*** on education and outreach in 1997.[15]

Texas:

According to the PUCN, Texas spent ***$24 million*** on education in the first two years of retail choice and currently spends ***$750,000 annually*** on these efforts.[16]

Additional Resource Needs:

Florida is currently the #1 state for fraud in America.[17] The experience with deregulation across the country clearly points to higher amounts of consumer complaints and fraud. Multiple states from Massachusetts to Illinois are suing to end retail choice due to preying on vulnerable populations by unscrupulous providers. Texas saw a spike in consumer complaints to over 17,000 in a year after they switched to a deregulated market.[18]

Regardless of consumer fraud concerns, increased state agency staffing would be necessary to handle the shift to a deregulated market in Florida. Last year, the Nevada PUC estimated it would need to spend $2.2 million in additional staffing and software needs if the state's deregulation ballot amendment had passed.[19]

From management to addressing complaints of fraud, deregulation means a larger state workforce to implement, administer, and monitor the new marketplace.

[13] http://mlis.state.md.us/1999rs/fnotes/bil_0000/sb0300.PDF
[14] Source: PUCN, Energy Choice Initiative Final Draft Report, Docket No. 17-10001, April 2018, at 62-63.
[15] Ibid
[16] Ibid
[17] https://www.bizjournals.com/tampabay/news/2018/03/05/florida-retains-its-dubious-distinction-as-scam.html
[18] Texas Coalition for Affordable Power, History of Deregulation 2018, pg. 32
[19] Source: PUCN, Energy Choice Initiative Final Draft Report, Docket No. 17-10001, April 2018, at 62-63.

Stranded Costs:

Our FTI report detailed the significant impacts of stranded costs to state and local government revenues. Our report found that stranded costs as a result of deregulation in Texas alone reached.

The report by Concentric Research included in last week's binder indicates over ***$40 billion*** in stranded costs were authorized for recovery in Texas, California, Connecticut, Illinois, Massachusetts, Michigan, New Hampshire and New Jersey.[20]

Overpayments for retail choice providers are common and substantial:

Overpayments to retail choice providers are common and substantial in state after state with a deregulated market. These overpayments are especially problematic if state and local government users are paying more for electricity than they otherwise should.

Connecticut:

A 2015 Connecticut Office of the Consumer Counsel report concluded customers in retail choice contracts paid ***$58 million*** more than customers with a traditional provider.[21]

Illinois:

Attorney General Lisa Madigan found Illinois residents overpaid by ***$600 million*** when compared to traditional power provider.[22]

Maryland:

Maryland residents overpaid by ***$255 million*** between 2014-2017, according to the Able Foundation.[23]

Massachusetts:

Attorney General Maura Healy's March 2018 investigation into the state's retail choice market found residents overpaid by ***$253 million*** when compared to what they had paid for electricity from a traditional provider.[24]

New York:

A 2016 New York Public Service Commission investigation found residents overpaid retail choice providers by ***$817 million***.[25]

Rhode Island:

Rhode Island's Division of Public Utilities and Carriers found retail choice customers overpaid by ***$28 million*** over a 5-year period.[26]

Texas:

The 2018 annual report on energy deregulation in the state by the Texas Coalition for Affordable Power noted that deregulation cost Texas customers approximately ***$25 billion*** between 2002 – 2014.[27]

[20] Concentric Research, "Support for FIEC Financial Impact Statement," February 2019.
[21] https://www.nbcconnecticut.com/news/local/Connecticut-Residents-Overpaid-58-Million-for-Electricity-Officials-376410131.html
[22] http://www.illinoisattorneygeneral.gov/pressroom/2018_09/20180907.html
[23] https://www.abell.org/publications/marylands-dysfunctional-residential-third-party-energy-supply-market
[24] https://framinghamsource.com/index.php/2019/01/23/mass-attorney-general-files-bill-to-support-electricity-customers/
[25] https://www.timesunion.com/news/article/State-bans-sale-of-gas-and-electricity-to-low-10800442.php
[26] https://www.wpri.com/call-12-for-action/switching-to-a-competitive-power-supplier-could-cost-you-data-shows/1355116964
[27] Texas Coalition for Affordable Power, "Deregulated Electricity in Texas 2018 Edition" pg. 3

California's Cautionary Story:

As the first state to re-regulate after a disastrous deregulation experiment, California constitutes an important cautionary tale for Florida or any other state considering deregulation. While the proposed constitutional amendment does not require Florida to take the same actions California did in 2000-2001, it is important to note that California incurred massive debt from restructuring.

As the Public Policy Institute of California notes, the state ended its foray with deregulation after taking on ***$42 billion*** in long-term power contracts to stop the rolling blackouts during the state's energy crisis.[28]

CONCLUSION

As our brief paper summarizes, deregulation affects state and local government revenues not just in terms of tax impacts, but also in terms of additional spending. Whether that spending is required for public education, public assistance, additional staffing, higher electric costs to government entities or operational costs for an independent system operator, the fact is that the proposed deregulation amendment will cost state and local governments more than just tax revenues; it will require the Legislature to appropriate hundreds of millions of dollars in order to be implemented. We respectfully request that you consider these additional costs to state revenues in addition to the associated tax implications for state and local governments.

[28] Public Policy Institute of California, "The California Electricity Crisis: Causes and Policy Options," pg. 81 https://www.ppic.org/content/pubs/report/R_103CWR.pdf

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Florida League of Cities and Florida Association of Counties

SUBJECT: Financial Impact Statement for the Proposed Amendment: Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice

DATE: March 3, 2019

SUMMARY

The proposed "Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice" amendment (Initiative) to Florida's constitution generally grants customers of investor-owned utilities (IOUs) the right to choose their electricity provider and to generate and sell electricity. Should the Initiative pass, the Legislature will be required to adopt laws providing for competitive wholesale and retail markets for electricity generation and supply, and consumer protections, by June 1, 2025. The Initiative limits IOUs to construction, operation, and repair of electrical transmission and distribution systems. Municipal electric and cooperative utilities may opt into competitive markets.

Initial indications are the Initiative will have a material financial impact on the membership of the Florida League of Cities and the Florida Association of Counties largely because the amendment will affect the franchise fees, public service taxes (PST) and ad valorem taxes received by Florida's local governments. The magnitude and timing of the financial impact that will occur will be primarily determined by the Legislative implementation if the Initiative is approved by Florida voters.

LOSS OR REDUCTION OF ELECTRIC FRANCHISE FEES

Municipal electric franchises in Florida have existed since the last quarter of the 19th Century. Like all Florida local government franchises, these electric franchise agreements constitute a special privilege conferred by cities and counties upon individuals or corporations which does not belong to citizens of the local government as a common right. When a franchise is accepted, it becomes a contract and is entitled to the same protection under constitutional guarantees as other property. In other words, such franchises are both legislative act and binding mutual contract. Cities and counties (grantors) are authorized to charge the holder of the franchise (grantee) a franchise fee, which is a type of proprietary fee, based on the notion of renting the rights-of-way to operate a business which the local government itself could operate.

Electric service franchise are typically granted by an ordinance which is also a contract. Currently, there are approximately 350 municipal and 15 county electric franchise agreements. These electric service franchises have been granted to IOUs, rural electric cooperatives, and even other municipal electric utilities. Legal authorization enabling cities to require electric franchises is diverse, including statutory home rule, s. 166.011, F.S., s. 180.14, F.S., numerous special act charters, and the common law municipal prerogative to serve. Counties share similar legal authority. As a part of the 1951 act which initially created state regulation of the electric rates of investor owned utilities, the Florida Legislature carefully and deliberately preserved cities' right to franchise electric service:

> *"(2) Nothing herein shall restrict the police power of municipalities over their streets, highways, and public places or the power to maintain or require the maintenance thereof or the right of a municipality to levy taxes on public services under s. 166.231 or affect the right of any municipality to continue to receive revenue from any public utility as is now provided or as may be hereafter provided in any franchise." S. 11, Chapter 26545, Laws of Florida (1951), codified as s. 366.11, F.S., and often referred to as the "Dowda Bill."*

Franchise fees are one of the largest sources of revenues cities and counties receive from the sales of electricity. For the last decade, the amount of annual electric franchise fees paid to cities ranges between $550 to $600 million and the amount paid to counties is approximately $150 million. Franchise fees are paid pursuant to franchise agreements, which exist between utilities and municipalities or counties. Typically, a local government will collect franchise fees from a utility with the payments based on a percentage of the utility's gross billings. The amount of franchise fees paid is a direct function of utility electric sales.

While electric service franchise agreements are not completely uniform, most contain certain basic provisions, including:

- Grant of authority to operate and provide electric service using local government rights of way (either non-exclusive or exclusive) in return for payment of six percent of gross billings from electric sales within the city limits or unincorporated county.
- Grant of the right to install and maintain electric distribution facilities in local government rights of way for a defined term ranging from 20 to 30 years
- Grantor commitment not to compete
- Grounds for forfeiture by either party
- Grantee commitment to relocate utilities under certain circumstances
- "Favored Nations" provision that enables either party to "reopen" the franchise agreement if either party executes another franchise with differing terms

- Termination rights to Grantee if electricity is deregulated (the “Retail Wheeling Clause”)

In addition, approximately 50 such franchise agreements include an option for Grantor to purchase the distribution facilities, exercisable if the franchise expires without being renewed or extended. These “purchase options” are valuable property rights that exist in favor of local governments.

It is probable that municipal and county franchise fee revenues will drop precipitously under the Initiative for several reasons. First, new retail providers using incumbent utilities’ distribution facilities will likely pay nothing. These new sales will not be subject to the franchise agreements and associated fees. Nothing presented to the Financial Impact Estimating Conference or in the ballot language suggests that under the Initiative, retail electric providers using the incumbent utility’s distribution lines would enter into franchise agreements or otherwise obligate themselves to pay franchise fees or their equivalent. Sales of electricity by new retail electricity providers that are facilitated by the proposed amendment will displace sales by utilities.

Second, as incumbent utility sales decrease, existing franchise fee revenues will decrease because the fees are based upon a percentage of the incumbent utility’s sales. If IOUs no longer bill customers for generation, transmission, or distribution costs, the revenue from these fees will be significantly reduced or even eliminated completely. While reasons one and two arise by virtue of attrition of franchise fee revenue caused by displaced retail sales, even if the attrition of franchise fee revenue caused by displaced retail sales fails to materialize, most of the current electric franchises contain a variety of provisions that permit incumbent utilities to reopen, renegotiate, and in many instances, terminate the franchise if the state were to impose “retail wheeling.” These provisions are drafted in various ways: some provide for termination if the city or county cannot impose a franchise fee on the other retail electric provider; some provide for termination if the most “favored nations clause” cannot be honored based on preferential treatment to another provider, such as the payment of a lesser or no franchise fee; and some provide for outright termination if as a consequence of any legislative, regulatory or other action by the state, any person is permitted to provide electric service within the local government jurisdiction which creates a competitive disadvantage to the franchise holder.

Finally, the Initiative contains a prohibition against “granting of either monopolies or exclusive franchises for the generation and sale of electricity.” This language could easily be construed to prohibit the renewal of existing franchises, since most of the existing franchises contain language that permits the operation and supply of electricity. This could erase all franchise fees as the existing franchises expire.

LOSS OF ANCILLARY FRANCHISE RIGHTS

Prior to the creation of constitutional “Home Rule” in the 1968 Constitution and the passage of Chapter 73-129, Laws of Florida (1973), the Florida Legislature exercised more direct control over cities and counties. Both special act charters and general law (s. 167.22, F.S.) limited franchise terms to 30 years. The statute required purchase options and allowed the local government to decide whether or not to buy all or some of the facilities utilized in the franchise agreements.

The law provided that valuation would take place pursuant to arbitration. Finally, the statute provided that a franchise without the term limit or the purchase option would be void.

When it implemented the 1968 constitutional home rule amendment in 1973, the Florida Legislature converted the purchase option mandate to a discretionary power. Since 1989, Florida courts have routinely validated the options and the valuation results. At least two municipal electric systems (Orlando and Winter Park) were transferred to cities by means of the option.

Utility appraisers may vary on the amount but agree that the authority to exercise options are a valuable right. Using an option versus exercising the eminent domain power results in significantly lower transactional costs, ranging, from 5 to 20 percent of the utility value. If the purchase option defines the method of valuation and other purchase terms (i.e. capping intangible values at 10 or 20 percent, as has been done in franchise agreements) savings of 10 to 40 percent of the purchase price could be realized. Some decisions have ruled that things like stranded costs do not apply. Others have determined that the selling utility is not entitled to business damages which would otherwise be available in eminent domain proceedings under state law. The reduced acquisition costs are considered to be within a range of 15 to 50 percent of value. For example, if the value of a utility system in eminent domain is $50 million, the savings could easily be in the millions of dollars. The most recently completed Florida electric municipal arbitration (City of Bushnell, April 2017) easily resulted in a savings of $13 million. This amount equals the difference between the incumbent utility's claimed value based on eminent domain concepts ($18+ million) and Bushnell's proposed $5.1 million offer which was accepted by the Arbitration Panel.

Despite containing assurances that "nothing…shall be construed to affect the existing rights or duties of municipally owned electric utilities," the Initiative by its very terms "prohibit(s) any granting of either monopolies or exclusive franchises for the generation and sale of electricity." This provision could be construed to terminate the authority of local governments to grant new electric franchises to IOUs. In addition, the "retail wheeling" clauses and similar clauses will result in the termination of many of the municipal electric franchises as noted above. Termination of these rights now enjoyed by those receiving municipal electric franchises will result in the termination of at least 50 of these valuable municipal property rights to purchase the distribution facilities, resulting in a substantial loss of value.

LOSS OF PUBLIC SERVICE TAX REVENUE

Since 1945, Florida has authorized the collection of a PST by municipalities. This tax, originally levied on electricity, metered or bottled gas, water service, and telephone and telegraph service, was called the municipal utility tax. In 1972, the Florida Supreme Court ruled that the Florida Constitution granted charter counties the authority to levy the municipal service tax. Today, municipalities and charter counties may levy, by ordinance, a PST on the purchase of electricity, metered natural gas, liquefied petroleum gas either metered or bottled, manufactured gas either metered or bottled, and water service. The tax is levied only upon purchases within the municipality or within the charter county's unincorporated area and cannot exceed ten percent of the payments received by the seller of the taxable item. The tax proceeds are considered general revenue for the municipality or charter county, meaning the tax proceeds may be utilized for any purposes. Municipal collections of the PST on the purchase of electricity were $ 780 million for fiscal year 2016-2017. Charter county collections of the PST were $259 million for the same time period.

Based on initial research, four municipalities and two counties have explicitly pledged the PST as primary or sole repayment for bonds. This count does not include local governments that have utilized covenant to budget and appropriate, which is a security for debt to a covenant to budget and appropriate legally available non-ad valorem revenues, and securities, where the PST is a secondary pledged revenue source.

Probable impacts on the PST are expected to result from a reduction in the tax base which could occur in three ways. The first would be an overall reduction the amount of electricity purchase, due to the increase in self-generation of electricity and onsite consumption. The extent that this would occur has yet to be determined. The second impact will come from the anticipated decrease in the purchase price of the electricity.

Finally, the tax is levied upon, among other things, the purchase of electricity within the city limits. Since franchise fees may be included in the base for electric sales, PST levies will be reduced based upon the projected reduction in franchise fees. More importantly, decisions rendered on tax exemptions for gross receipts taxes based on utility service sales indicate that, to the extent retail electric service providers make the sale out of the city or the county, the PST might not apply, thus reducing further the revenues from the PST. The displacement of IOU sales may reduce revenues from other taxes and fees as well, depending upon whether the applicability provisions for each tax and fee are ultimately construed to apply to sales by out-of-state (or out-of-local government) retail marketeers. It is very probable that the absence of a use tax equivalent to the PST on electricity purchased outside the state, county, or city, used in the city or county limits, will reduce the PST revenues to local governments.

LOSS OF AD VALOREM TAX REVENUE

The ad valorem tax is local governments' only constitutionally authorized tax and is one of the most important revenue sources for municipalities and counties. Property taxes are reserved for local governments --- the state constitution prohibits the state from levying the tax and Florida's cities, counties, school districts and special districts depend on the $31.4 billion this tax provides annually. Property taxes are levied on both real and tangible personal property (TPP). The taxable value of real property and TPP is its fair market value minus any exclusion, differential, or exemption allowed by Florida laws. Utilities are capital intensive and have significant real and tangible personal property tax obligations. Florida's IOUs paid $1.1 billion in property taxes in 2018.

Many counties rely heavily on property tax revenue from utilities, especially small, rural counties where utility property can comprise a significant portion of the tax base. The Initiative would likely reduce property tax revenues. If deregulation and the required divestiture of generation property result in more out-of-state generation of electricity, there would likely be corresponding loss of in-state generation property, reducing Florida's property tax base. A much more significant reduction in Florida's property tax base could result from the forced divestiture of generating facilities. This reduction would be due in part to the IOUs stranded costs, which is largely the amounts by which the book values of utility generation assets exceed their market values. Sales of IOU property at below book value would reduce the appraised and taxable values of those properties. If the required divestitures were to result in "fire sale" prices, this would further reduce the selling price and thus the appraised and taxable values of IOU property.

The language of the Initiative is ambiguous as to whether the current IOUs would be able to own the transmission and distribution system. The proposed amendment requires the Legislature to pass a law to "limit the activity of investor-owned electric utilities to the construction, operation, and repair of electrical transmission and distribution systems." It does not specify that the IOUs can own the systems. If this is interpreted as requiring the divestiture of ownership of the transmission and distribution system, then the value of these components of the IOUs' total tax base would be compromised.

FLORIDA MUNICIPAL ELECTRIC FRANCHISE
REPRESENTATIVE SAMPLE

Index

Florida Power & Light

1. 2007 City of Anna Maria
2. 1998 Broward County
3. 2011 City of Cape Canaveral
4. 2008 Charlotte County
5. 2004 City of Daytona Beach
6. 2009 City of Fort Lauderdale
7. 2009 Town of Highland Beach
8. 2011 City of Holly Hill
9. 2009 Town of Malabar
10. 2015 Martin County
11. 2007 City of Melbourne
12. 2010 City of Miami
13. 2010 City of Miami Shores
14. 2009 Palm Beach County
15. 2014 Town of Palm Beach Shores
16. 2011 City of Palmetto
17. 2006 Town of Pembroke Park
18. 2007 Sarasota County
19. 2014 City of South Miami
20. 2009 City of St. Augustine
21. 2017 City of St. Augustine Beach
22. 2014 Village of Tequesta
23. 1996 Village of Wellington

Florida Power Corporation / Progress Energy / Duke Energy Florida

1. 2004 City of Apopka
2. 2006 Town of Belleair
3. 2001 City of Belleair Beach
4. 2011 City of Belleview
5. 2001 City of Dunedin
6. 1999 Town of Eatonville
7. 1996 City of Haines City
8. 1996 City of Largo
9. 2014 Town of Lee

10. 2003 City of Longwood
11. 1996 City of New Port Richey
12. 2001 Town of North Redington Beach
13. 2004 City of Ocala
14. 1999 City of Port Richey
15. 1996 City of St. Petersburg

Tampa Electric Company

1. 2010 City of Plant City
2. 2008 City of Polk City
3. 2008 City of Tampa

Gulf Power Company

1. 2010 City of Lynn Haven
2. 2013 City of Parker

From: Steve Schriever <steve@fishkind.com>
Sent: Monday, February 25, 2019 11:33 AM
To: Schenker, Pamela
Subject: RE: FIEC Notebook has been posted

Good Morning Pam

I am providing the reference for the adjusted sales values of generation plants as requested by the FIEC committee.

The data was taken from the **Concentric Report: Competitive Energy Market for Customers of Investor Owned Utilities; Support for FEIC Financial Impact Statement; (Recent Power Plant Sales; Page 30).**

It is my understanding that the committee already has this report.

Thanks for organizing my teleconference presentation.
Steve Schriever

FLORIDA ENERGY CHOICE

CITIZENS FOR ENERGY CHOICES

Competitive Electricity Choice for Consumers

The proposed amendment would give customers of investor-owned utilities the right to purchase electricity in a competitive market:

- Utilities will continue providing rate-regulated delivery and other natural monopoly services
- The Public Service Commission will oversee suppliers, generators, and utilities to ensure reliability, safety and customer protection
- Competition will reduce prices while increasing efficiency, customer satisfaction, innovation and the availability of green energy

Competitive Electricity Choice for Consumers

Energy competition can bring unparalleled benefits to the State of Florida and all of its citizens and businesses.

- When retail electric providers compete – when customers have the right to choose their preferred provider, rates, services – **savings**, **satisfaction** and **innovation** increase by leaps and bounds

- When utilities focus on exclusively utility services – the **delivery**, **reliability** and **safety** that are the core of their natural monopoly businesses – efficiency increases while cost decreases

- When generators compete, they also become more efficient and less costly, energy becomes greener, and ratepayers are never burdened with the cost of bad or unnecessary investments

Why an Amendment vs. Legislative Channels?

- Big utilities have used their extensive financial resources to block previous legislative attempts, including a measure introduced through the Constitution Revision Commission (CRC)

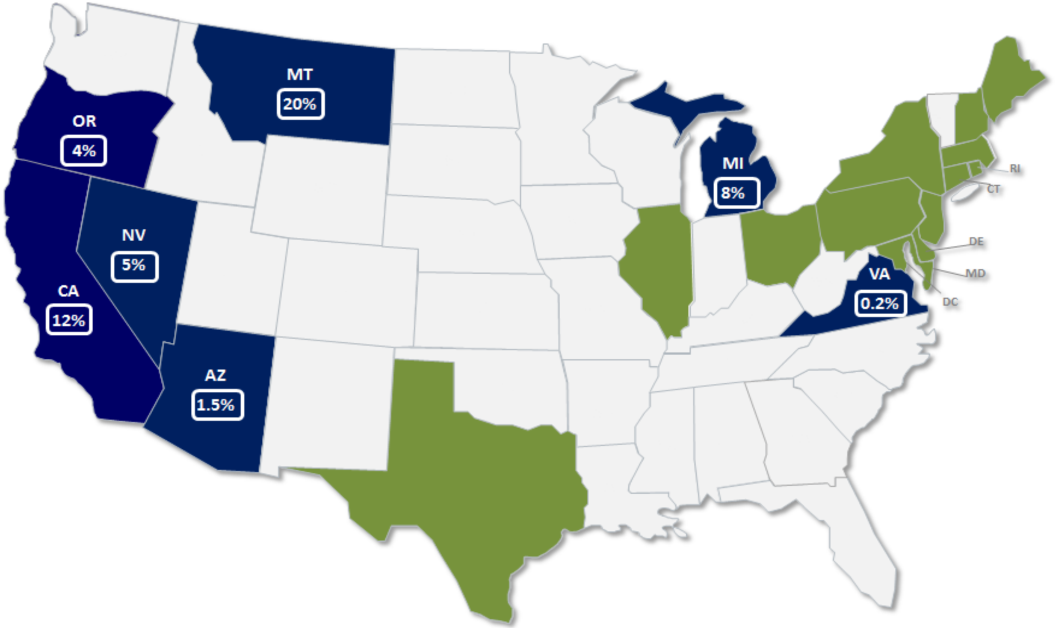
- Ensures consumers’ right to choose their electric provider is protected and cannot be changed by political spending

Competitive States vs. Hybrid (Limited Choice) States

- The states shaded green are competitive states; those shaded blue are hybrid states. Texas is the only fully restructured state.

- Partial restructuring – or worse, capped or otherwise limited choice – does not offer the same benefits as a fully competitive wholesale and retail market

- Texas and the 13 states with choice have shown dramatic savings compared to the seven hybrid and 29 no-choice states

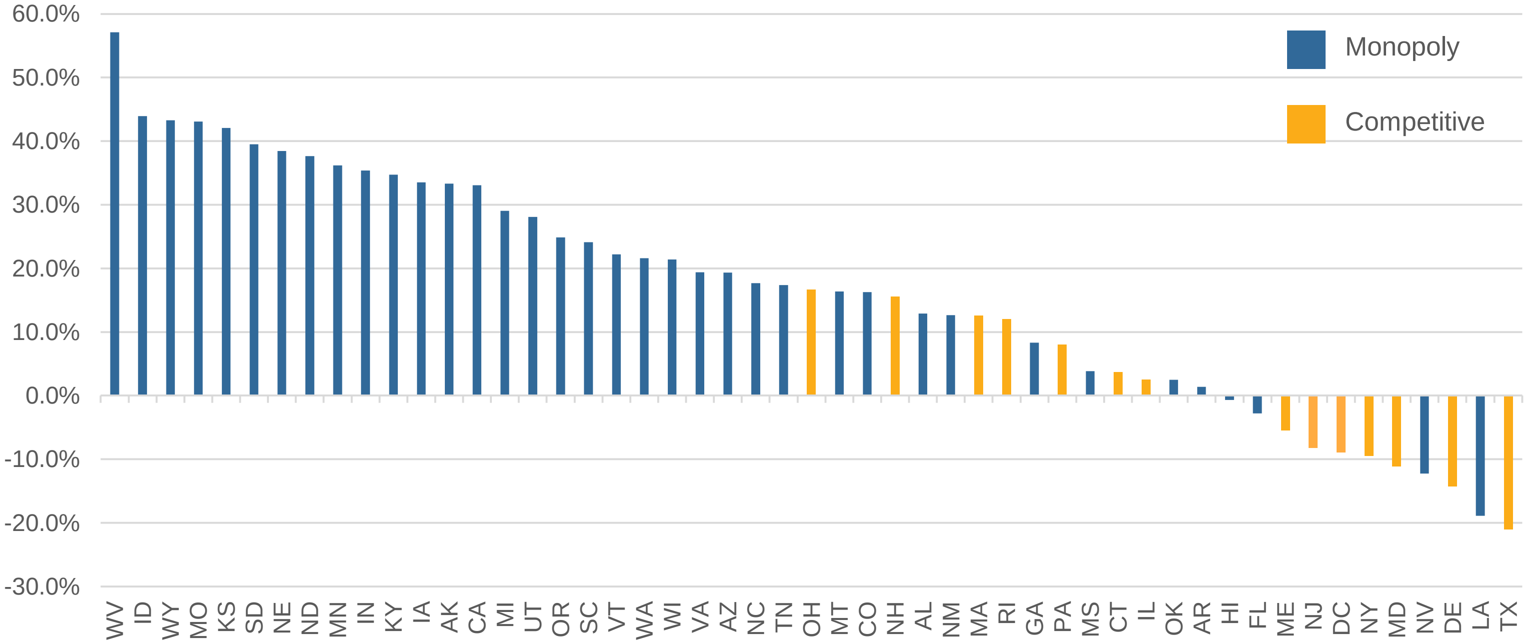


Source: (1) Energy Information Administration (EIA-826); 2016 total annual MWh load by state for all non-residential & residential load (all sectors)
(2) DNV GL Retail Energy Outlook, H2 2016; All 2016 non-residential & residential switched load by state (estimate as of January 2017)

Retail Price Changes, Energy Choice vs. Monopoly

Price Increase by Percentage, 2008 – 2018

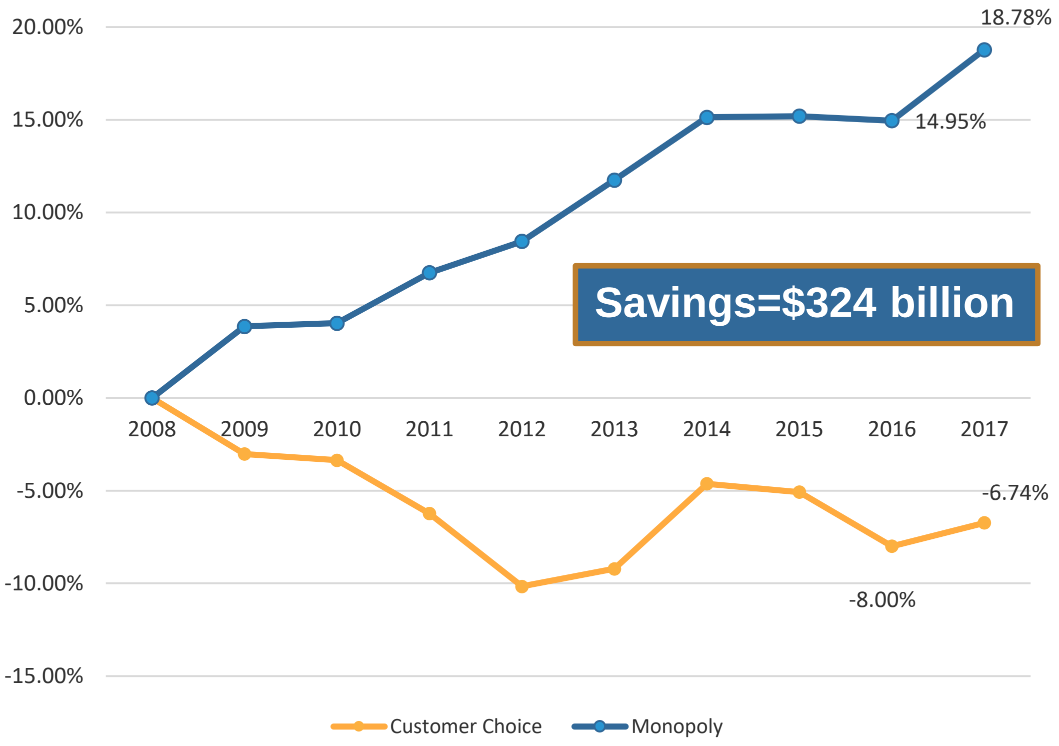
During this period, competitive states showed the lowest price increases – and, in many cases, price decreases.



Source https://www.eia.gov/electricity/data.php#sales

Choice States vs. Monopoly States

All Sector Weighted Average Price Change by Percentage, 2008-2017



Source: https://www.eia.gov/electricity/data.php#sales

Pd. pol. ad. by Citizens for Energy Choices P.O. Box 1101 Alachua, FL 32616

Competition Makes Retail Markets More Efficient

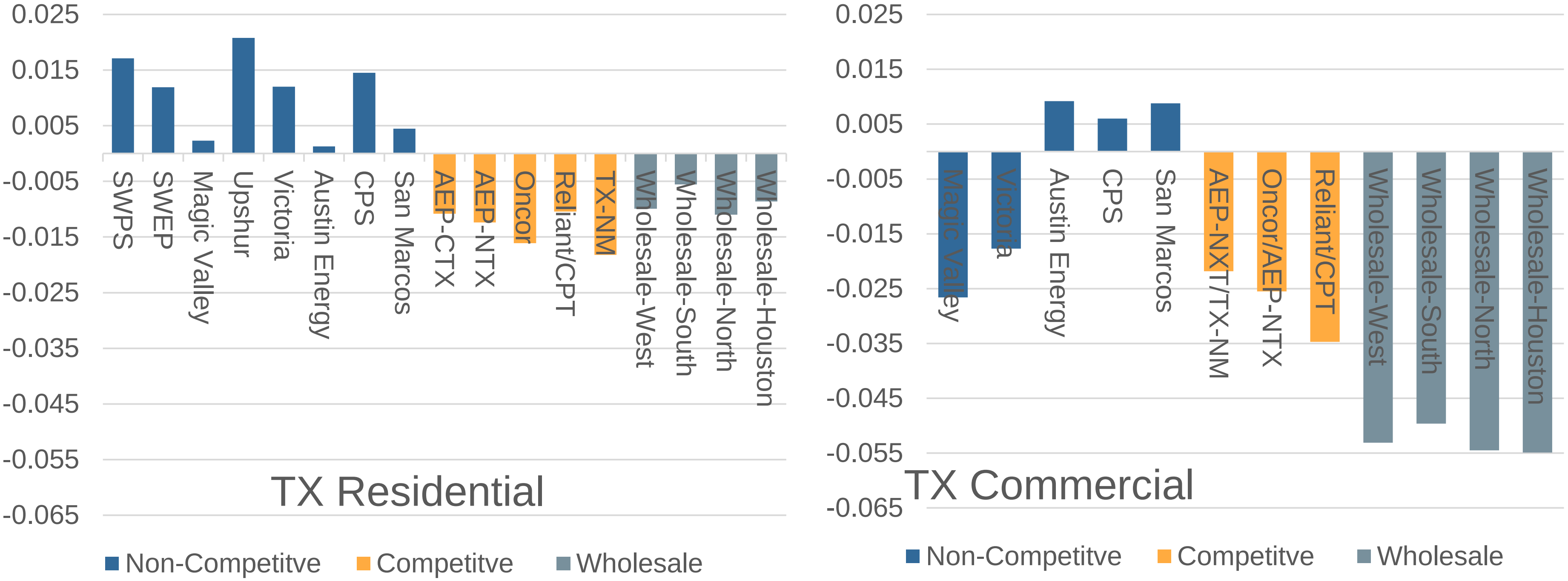
Rice University Study Comparing Competitive and Non-Competitive Texas Markets

"In this study, we find that residential rates in competitive and non-competitive areas of Texas have behaved in a manner that is consistent with economic theory. More specifically, residential rates in competitive areas are highly reflective of wholesale rates, which suggests that electricity providers are minimizing costs in meeting market demands. By contrast, residential rates in non-competitive areas do not generally reflect wholesale rates. Furthermore, we find a shrinking gap between residential rates and wholesale rates in competitive areas, which is consistent with improvements in firm and market efficiency. This also has not generally been the case in non-competitive areas."

Source: Source: Hartley, P., Medlock III, K., Jankovska, J. (2017). Electricity reform and retail pricing in Texas. Retrieved from: https://www.bakerinstitute.org/media/files/research_document/7d32313b/CES-pub-TXElectricity-060717.pdf

Competition Drives Lower Prices

Texas Residential and Commercial Rates Changes, 2002-2016



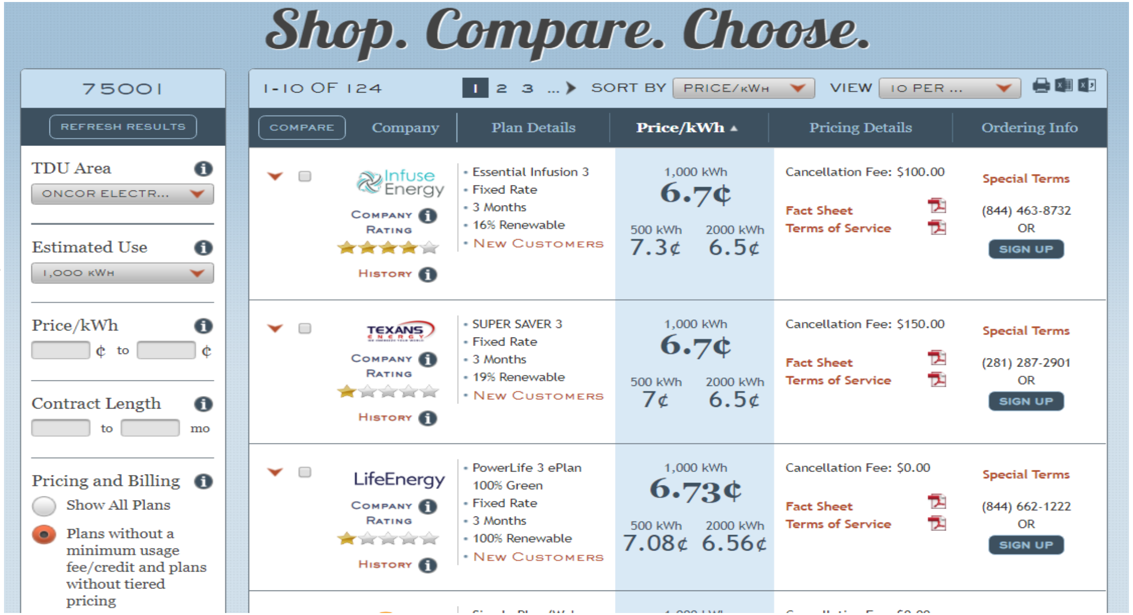
Source: Hartley, P., Medlock III, K., Jankovska, J. (2017). Electricity reform and retail pricing in Texas. Retrieved from: https://www.bakerinstitute.org/media/files/research_document/7d32313b/CES-pub-TXElectricity-060717.pdf

*Note: at least some of the non-competitive coops listed above participate in the ERCOT wholesale energy market.

Transparent Shopping (1of 2)

Shopping Website by PUCT Makes Savings Simple

- PUCT’s “Texas Electric Choice” campaign has the goal of educating Texans about electric choice
- The "Power To Choose" website was visited by 1,370,411 unique and potential customers between September 1, 2016 through August 31, 2018

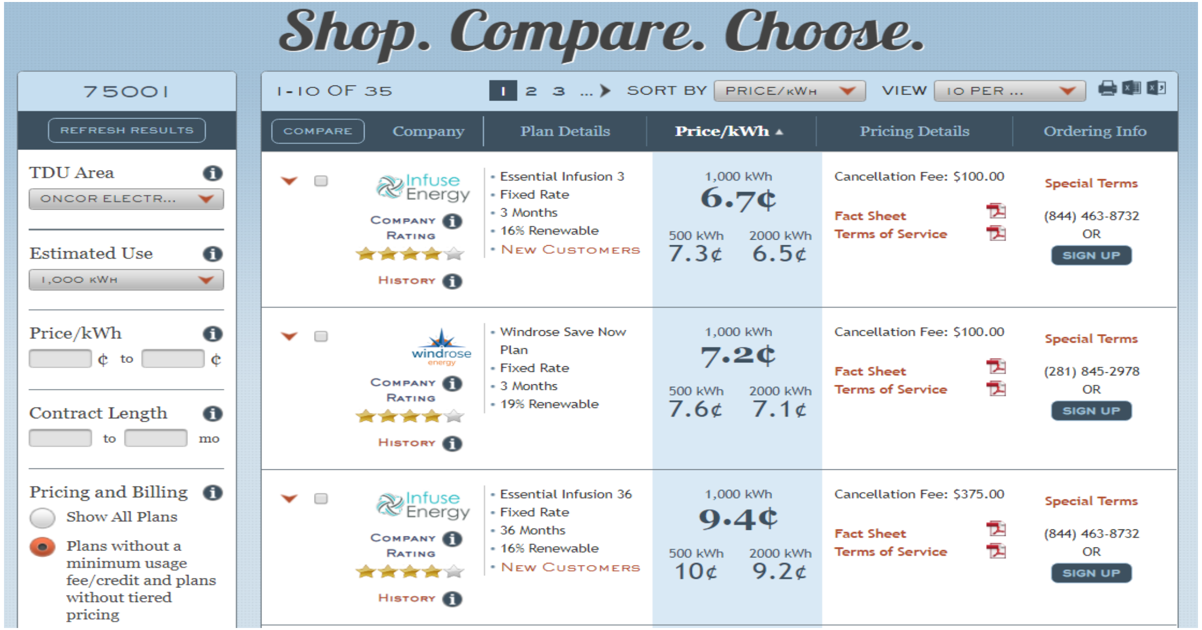


Source:http://powertochoose.org/en-us/Plan/Results#

Transparent Shopping (2 of 2)

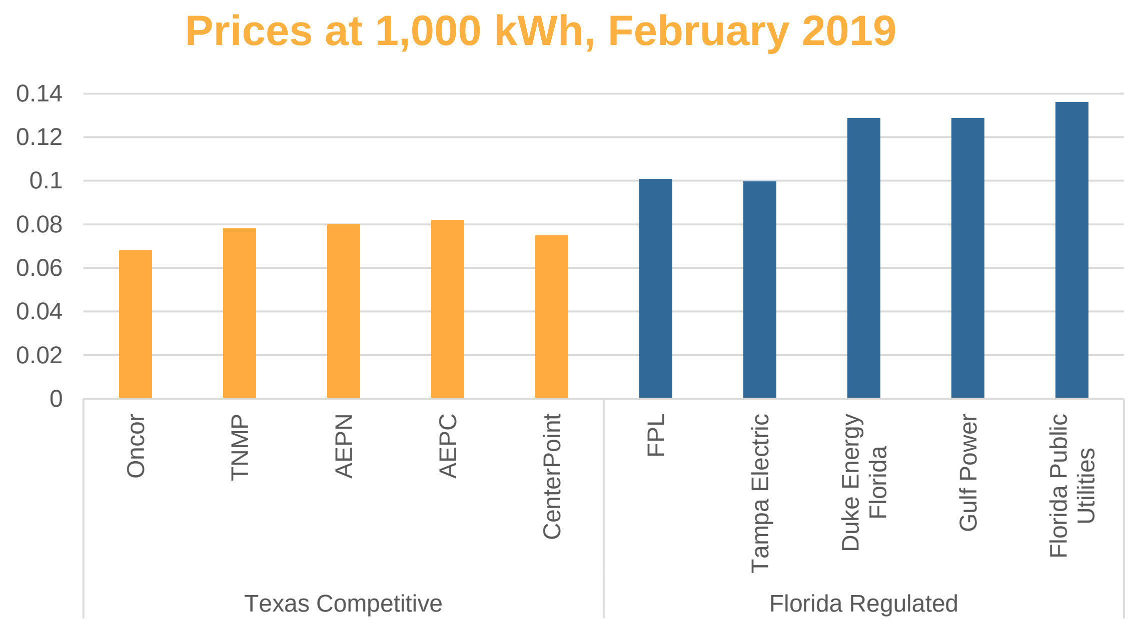
Customers Get to Choose What is Most Important to Them

- Low Prices
- Renewable Energy
- Company Rating
- Fixed or Variable



Source:http://powertochoose.org/en-us/Plan/Results#

Texas Competitive Electric Prices vs. Florida Regulated Utility Prices



Source: www.powertochoose.com; http://www.psc.state.fl.us/ElectricNaturalGas. Accessed 2/28/19.

https://www.voltep.com/volt-electricity-efl-808-american-electric-power-central-power-to-choose-e-bill-3.html

https://www.constellation.com/bin/residential/Terms_TX?versionNum=01H35

https://api.brilliantenergy.com/Agreements/GetResidentialDocument?productToken=f7586d3c-54b0-486e-85cc-dc82eb98de89&documentType=efl&language=english

https://88fd201f32c53c2bd0fb-11ba98ed637230a2314ec7c228a44bda.ssl.cf5.rackcdn.com/201902/EFL-20190226-105503-Essential%20Infusion%203%20(English).pdf

https://88fd201f32c53c2bd0fb-11ba98ed637230a2314ec7c228a44bda.ssl.cf5.rackcdn.com/201902/EFL-20190226-105503-Essential%20Infusion%203%20(English).pdf

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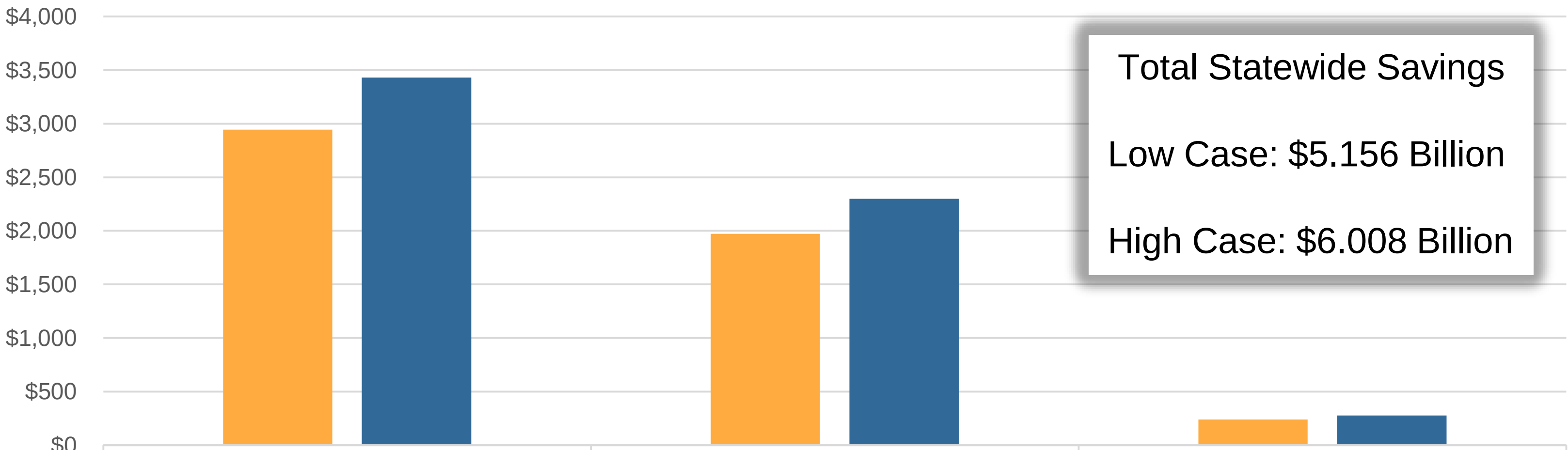
Competition Is an Investment That Pays Off

If Competition Existed in Florida, Customers Would See Significant Savings

Potential Direct Yearly Savings from the Introduction of Statewide Electric Competition in Florida

(Dollar Amounts in Millions of 2016 Dollars)

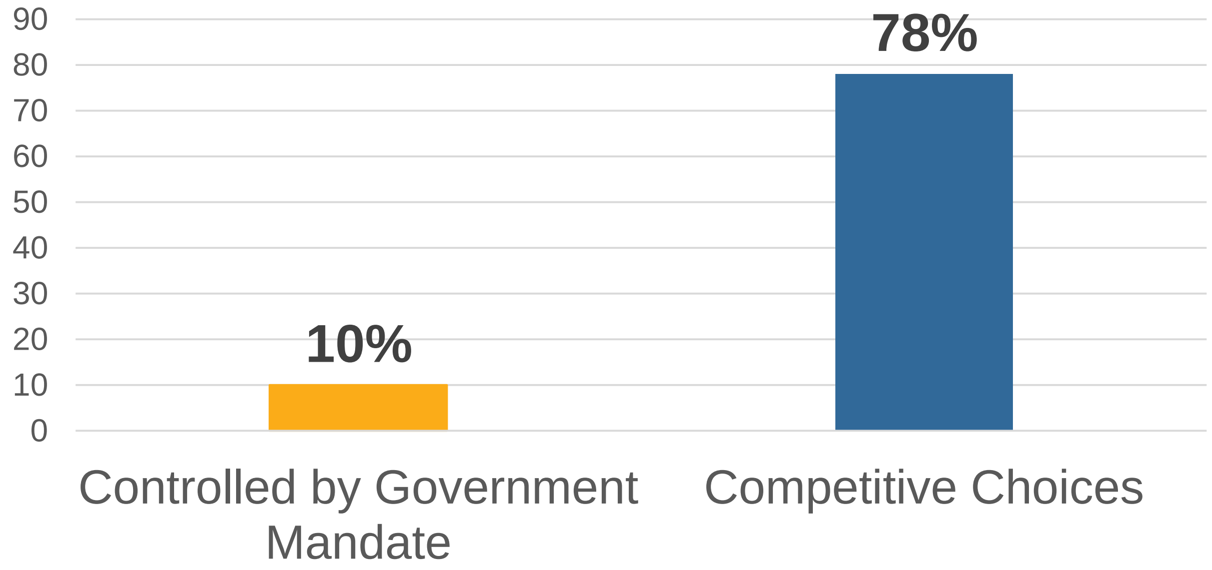


	Residential	Commercial	Industrial
Low Case	$2,944	$1,973	$239
High Case	$3,431	$2,299	$278

Source: The Perryman Group (2017), "Potential Economic Benefits of Statewide Competition in the Florida Electric Power Market: A Preliminary Assessment" www.perrymangroup.com

Florida Consumers Want Choice

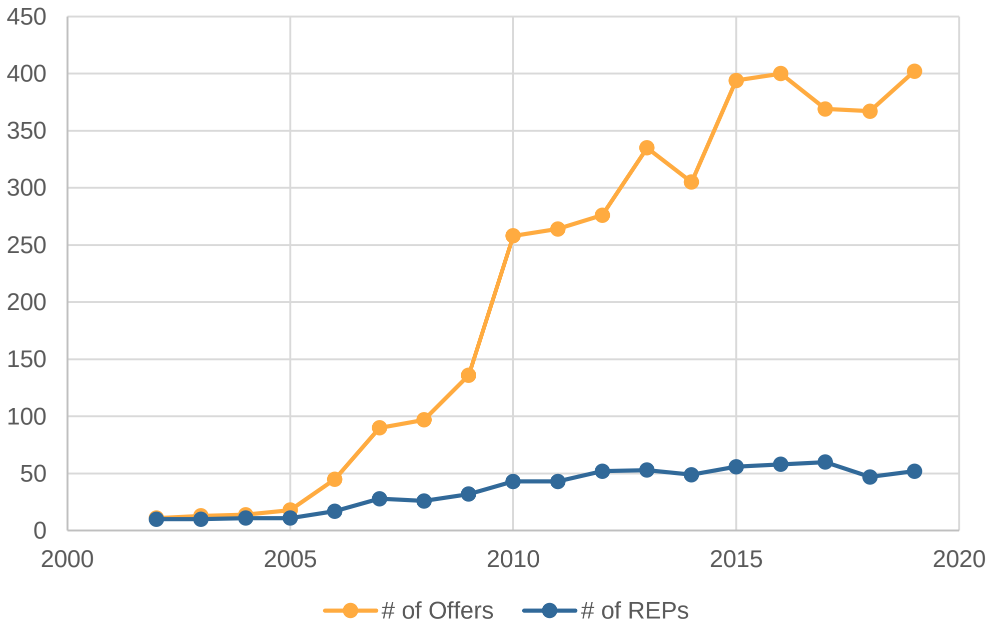
Q: Should electricity and natural gas products and rates be controlled by government mandate OR should consumers be given competitive choices to meet their energy needs?



Source: American Coalition of Competitive Energy Suppliers. Survey of 500 energy consumers in Florida. (2017).
http://harperpolling.com/polls/american-coalition-of-competitive-energy-suppliers--florida-ohio-consumer-surveys

Competition in Texas Continues to Grow

The Number of Options Has Increased Exponentially Since 2002



Source: PUCT, www.powertochoose.org.
Number of residential offers in Oncor area at year-end through February 2019.

Competition Brings More Products and Services

Innovative Products Available With Energy Choice

Rate Options

- Time of use rates
- Fixed rates
- Index rates
- Prepaid rates

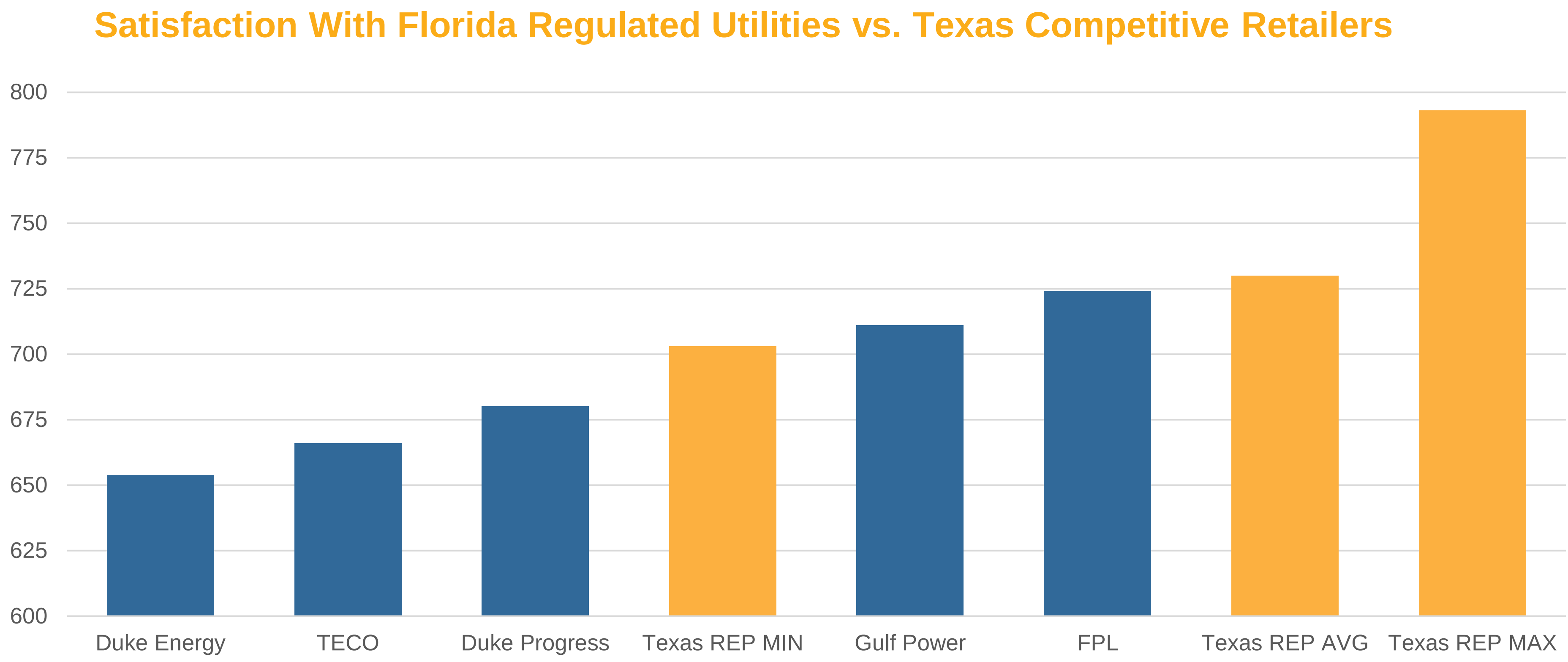
Green Products & Analytics

- Green & Renewable energy plans
- Home solar & distributed generation
- Battery storage
- Demand response programs
- Mobile power pack
- LED Lighting
- EV chargers
- Energy usage emails and graphs
- Energy usage and billing analytics

Additional Non-commodity Services

- Surge protection
- Internet service
- Cellular service
- Cable television
- Home security and automation
- Home warranty protection
- Identity protection
- Home energy checkup
- AC/Heater tune-ups
- Electric wiring warranty repair
- Home, renters and auto insurance
- Rewards and loyalty programs
- Home generators
- Furnace air filters
- Google Home
- Google Chromecast
- Nest thermostat
- Nest doorbell
- Nest camera
- Nest Protect

Competition Drives Satisfaction



Source: J.D. Power (2017). 2017 Electric Utility Residential Customer Satisfaction Study

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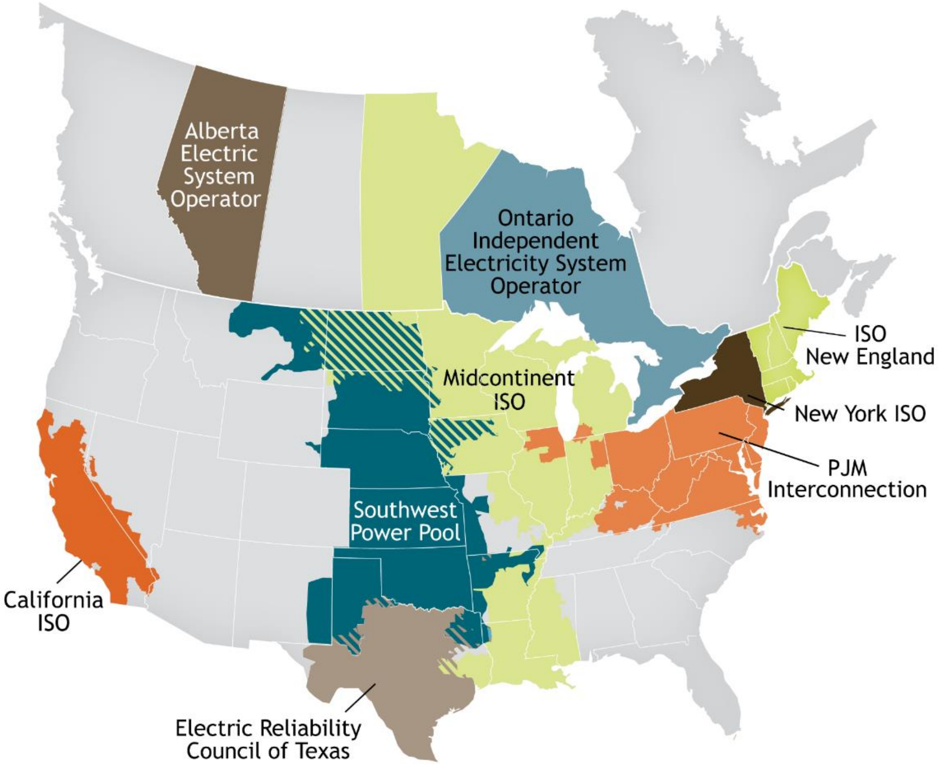
Competitive RTO/ISO Areas

- Each shaded area of the map is a competitive RTO/ISO area where generators compete. Most of the states in those shaded areas have some degree of electric choice.

- In Texas, over 46 GW of new generation has been built since energy choice was implemented.

- Competition works – Florida is the <u>only</u> high-population, high-demand state without a wholesale (and retail) electric market.



Restructuring and Reliability Go Hand-In-Hand

Oversight and Entrepreneurship Ensure Supply Meets Demand

Reliability is not negatively impacted by competition. Oversight ensures reliability:

- Two federal regulatory agencies (FERC/NERC) oversee the national electric grid
- Each state has its own public services/utilities commission
- The entire U.S. and Canadian electric system is overseen by eight Reliability Entities
- Each of the 10 wholesale market areas in North America is overseen by a grid operator (ISO/RTO)

In addition to this extensive oversight, the most populated areas in North America – two-thirds of Americans and half of Canadians – are located in wholesale market areas. Even in states where retail choice is limited or non-existent, wholesale competition markets have been operating since 1998 and reliability has only improved.

Reliability in ERCOT

Limited Reliability Events in ERCOT Unrelated to Restructuring

In a “Black Swan” event in February 2011, 225 generators failed due to an unprecedented combination of issues: extreme low temperatures, wind, ice, and snow; all-time high winter peak electrical demand; and fuel supply issues.

- 85% of unplanned failures due to 32 equipment failures, 10 external transmission, 108 freezing temperatures, 18 fuel curtailment, 23 low temperature limit.
- Nearly 15 GW of unplanned unavailable capacity as well as 12 GW of pre-scheduled outages resulted in rolling blackouts February 2.

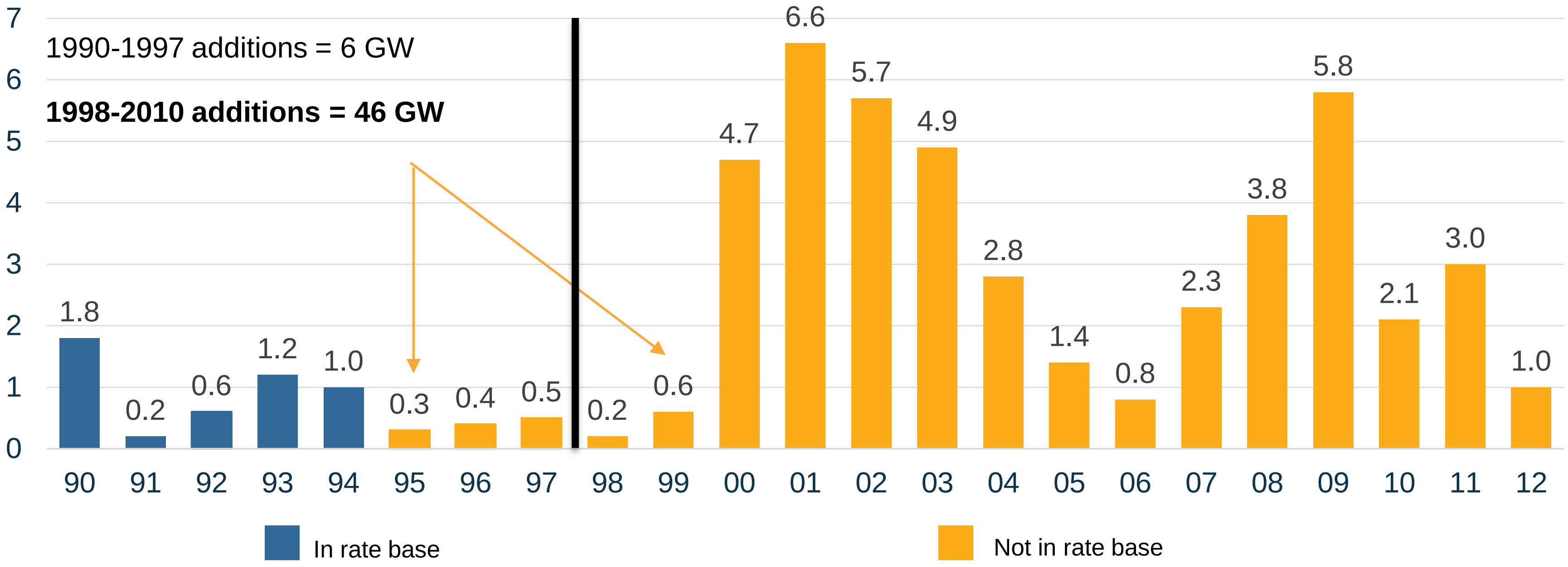
Lower Rio Grande Valley, where there is both limited generation and limited transmission, experienced a blackout in October 2014 due to failure of three generators combined with pre-scheduled outages and high load due to high temperatures.

In response to these events, ERCOT, PUCT, and market participants revised protocols, established new requirements and initiated investments to avoid future occurrences.

Source: https://www.texasre.org/CPDL/Forms/Event%20Analysis.aspx

Competition Spurred New Generation Investment in ERCOT

Capacity Additions in GW, 1990-2012



Source: Energy Velocity, NERC, PUC, IHS CERA as cited in Association of Electric Companies of Texas, Inc. (2015). ERCOT wholesale electric market:
Focus on resource adequacy presentation. Retrieved from: http://www.aect.net/wp-content/uploads/2015/01/Resource-Adequacy-JAN15.pdf

Competition Creates More Green Energy

Texas Has Become the Leader in Renewables

"The roots of Texas' renewables boom go back to 1999, when then-Gov. George W. Bush and a Republican-dominated legislature overhauled the Texas power market. The free market-oriented deregulation broke the grip of most monopoly utilities that controlled generation, transmission and retail sales of electricity and introduced competitive auctions for wholesale power.

Texas officials didn't invoke global warming to sell the program. Instead, they touted renewable energy as a consumer-choice issue, a jobs producer and a way to pump more money into rural counties.

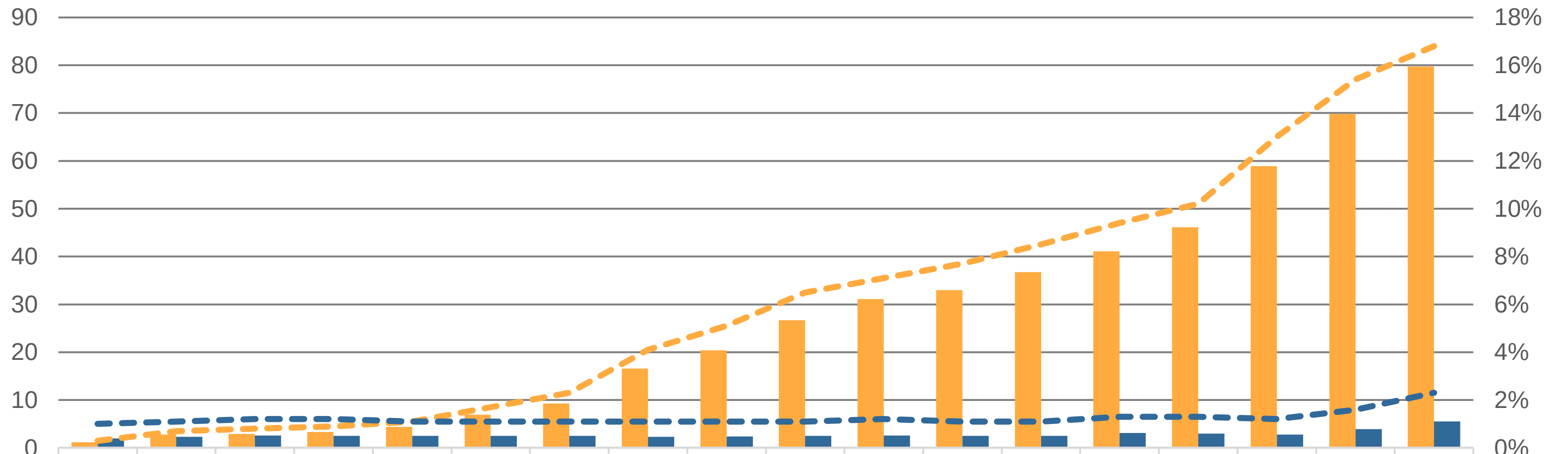
Residents of Houston currently can pick from 107 different rate plans offering 5% to 100% renewable power. In general, they are willing to pay a bit more to go green. Top-rated Reliant, a unit of NRG Energy Inc., charges 7.1 cents a kilowatt-hour for the plan that's all renewable versus 5.9 cents for one that's 5% green."

The Wall Street Journal, "Which State Is a Big Renewable Energy Pioneer? Texas" August 29, 2016

Competition Creates More Green Energy

Competition Will Bring Renewable Energy to Florida

Renewable Growth – Installed TW and Percentage of Generation



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
TX Renewable (TW)	1.2	2.8	2.9	3.3	4.4	6.9	9.3	16.6	20.4	26.7	31.1	33	36.7	41.1	46.1	58.9	69.8	79.7
FL Renewable (TW)	2	2.3	2.6	2.5	2.5	2.5	2.5	2.3	2.4	2.5	2.6	2.5	2.5	3.1	3	2.8	3.9	5.5
TX % Renewable	0.3%	0.7%	0.8%	0.9%	1.1%	1.7%	2.3%	4.1%	5.1%	6.5%	7.1%	7.7%	8.5%	9.4%	10.2%	13.0%	15.4%	16.8%
FL % Renewable	1.0%	1.1%	1.2%	1.2%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.2%	1.1%	1.1%	1.3%	1.3%	1.2%	1.6%	2.3%

Source: Electric Power Monthly, February 2017, Energy Information Administration (EIA) U.S. Department of Energy, http://www.eia.gov/electricity/monthly. Above charts do not include hydropower generation.

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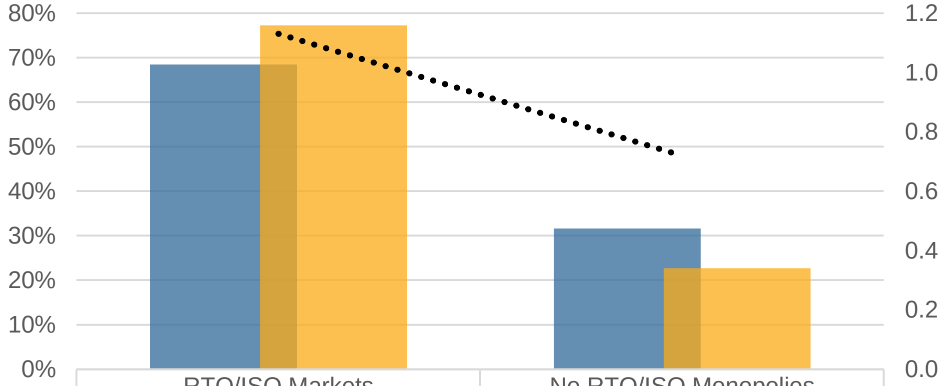
Competition Creates More Green Energy

Renewable Generation: Markets vs Monopolies

- Markets make up a greater percentage of all installed generation in the US (68.4%) but make up an even larger percentage of installed renewable generation (77.3%).

- Markets serve a higher percentage of the population, but do so more efficiently (73% of the population is served by 68% of the generation in market states, while 27% of the population is served by 32% of the generation in monopoly states).



	RTO/ISO Markets	No RTO/ISO Monopolies
% US Generation	68.4%	31.6%
% US Renewable	77.3%	22.7%
% US Population	73.1%	26.9%
Ratio	1.13	0.72

Source: Electric Power Monthly, February 2019, Energy Information Administration (EIA) U.S. Department of Energy, http://www.eia.gov/electricity/monthly. Above charts do not include hydropower generation.

Competition Benefits All Customers

Generate Revenue and Cut Costs

Municipals and co-ops that own generation can participate in the wholesale market:

- Sell excess generation when the market is high – generate revenue
- Buy energy when wholesale market costs are lower than the utilities' cost to generate – cut costs
- Enter into agreements with other utilities to buy, sell or trade excess generation to help manage costs
- Benefit from competitive investment in newer, more efficient generation that drives wholesale prices down

Source: TCAPTX (2017). Why join. Retrieved from: https://tcaptx.com/why-join

Competition Benefits All Customers

Aggregation Saves Money and Resources

Municipals and co-ops can aggregate their load to leverage buying power:

- The Texas Coalition for Affordable Power (TCAP), an Aggregator serving Texas municipals, works with Retail Providers and Competitive Generators to leverage the buying power of their members' 1.3 billion kWh annual load. This makes TCAP's membership a very large buyer of electricity, with the ability to negotiate prices and services to match their members' significant load.

- Aggregation of energy-related costs – such as energy consultants, issuing and reviewing RFPs, advocacy, contract review and legal expenses, even investing in advanced meter deployment and distributed generation projects – becomes much easier, effective, and economic as part of an energy-purchasing aggregation group.

Source: TCAPTX (2017). Why join. Retrieved from: https://tcaptx.com/why-join

Florida Utilities Already Participate in Competitive Markets

NextEra a Major Competitor in States With Wholesale and Retail Electric Markets

- NextEra's competitive affiliates serve 630,000 residential and 59,000 commercial customers in 14 states in the Midwest and Northeast U.S.
- NextEra has transmission and competitive generation throughout the United States and Canada, including:
  - Nearly 20k MW of generation, including nearly 4k MW of merchant generation
  - Operates in every ISO and RTO wholesale market
  - Sells energy, capacity, renewable energy credits, and ancillary services in competitive markets

Source: NextEra Energy Service (2017). Why NES?. Retrieved from: https://www.nexteraenergyservices.com/for-home/why-nes/
Source: NextEra Energy (2018). Corporate Responsibility Executive Digest - Corporate Profile. Retrieved from: http://www.nexteraenergy.com/pdf/Executive_Digest_Final.pdf
NextEra Energy (2016). Annual report. Retrieved from: http://nexteraenergy.com/pdf/annual.pdf

Florida Utilities Already Participate in Competitive Markets

NextEra a Major Competitor in States With Wholesale and Retail Electric Markets

- Of the total 46k MW generation capacity owned by NextEra Energy:
  - ~43% is in competitive markets (RTOs/ISOs)
  - Remaining ~57% is located in Florida
- NextEra is a major player in the Texas competitive markets:
  - Affiliate Gexa serves >146,000 residential and 6,300 commercial customers in Texas
  - Over $8 billion invested in ~3 GW Texas competitive generation assets
  - Seven Texas pipelines (>500 miles) to provide gas transportation, operate in the gas market, and serve its Texas generation

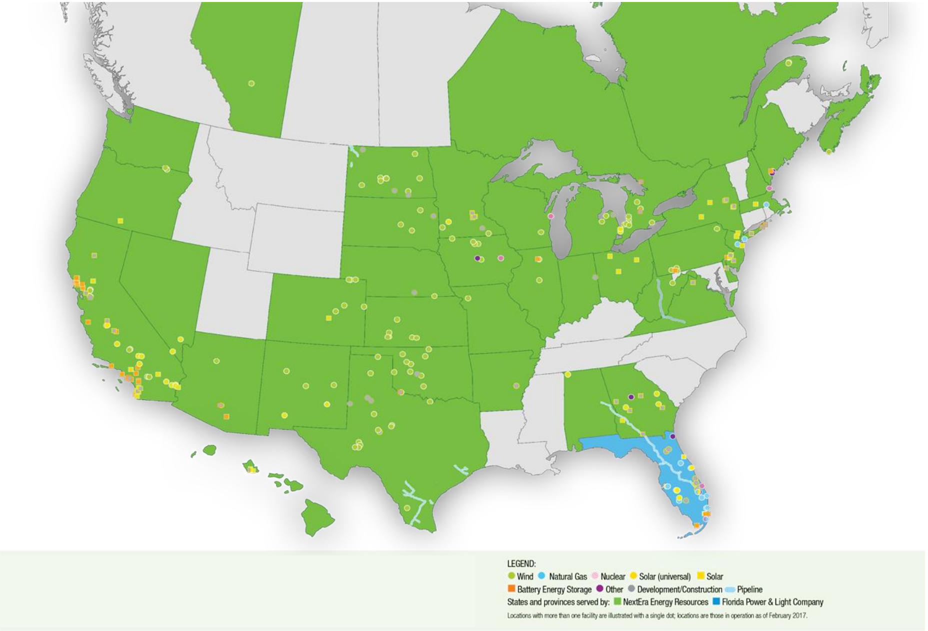
Source: NextEra Energy Service (2017). Why NES?. Retrieved from: https://www.nexteraenergyservices.com/for-home/why-nes/
Source: NextEra Energy (2018). Corporate Responsibility Executive Digest - Corporate Profile. Retrieved from: http://www.nexteraenergy.com/pdf/Executive_Digest_Final.pdf
NextEra Energy (2016). Annual report. Retrieved from: http://nexteraenergy.com/pdf/annual.pdf

Florida Utilities Already Participate in Competitive Markets

NextEra a Major Competitor in States With Wholesale and Retail Electric Markets

- NextEra has competed in the Florida natural gas commercial retail market through affiliate FPL Energy Services for over fifteen years

- FPL admits that they have limited competition in Florida and any changes in law or regulation that allow for electric competition could have a material adverse effect on FPL's business and financial condition



Source: NextEra Energy Service (2017). Why NES?.
Retrieved from: https://www.nexteraenergyservices.com/for-home/why-nes/
Source: NextEra Energy (2018). Corporate Responsibility Executive Digest - Corporate Profile. Retrieved from: http://www.nexteraenergy.com/pdf/Executive_Digest_Final.pdf
NextEra Energy (2016). Annual report. Retrieved from: http://nexteraenergy.com/pdf/annual.pdf

Citizens for Energy Choices

FLORIDA ENERGY CHOICE

Jon Wellinghoff

GridPolicy

What is Probable?

- *Taxes*
  - *Franchise*
  - *GRT & MPST*
  - *Property Taxes*

- *Costs of Implementation*
  - *ISO/RTO*
  - *Other Costs*

What is Probable?

- *Taxes*
  - *Franchise*
  - *GRT & MPST*

- *Review*
  - *Guinn Center Report*
  - *Governor's Energy Choice Committee*

What is Probable?

- *Taxes*
  - *Property Taxes*

- *Stranded Assets*
  - *Costs & Benefits*

Costs

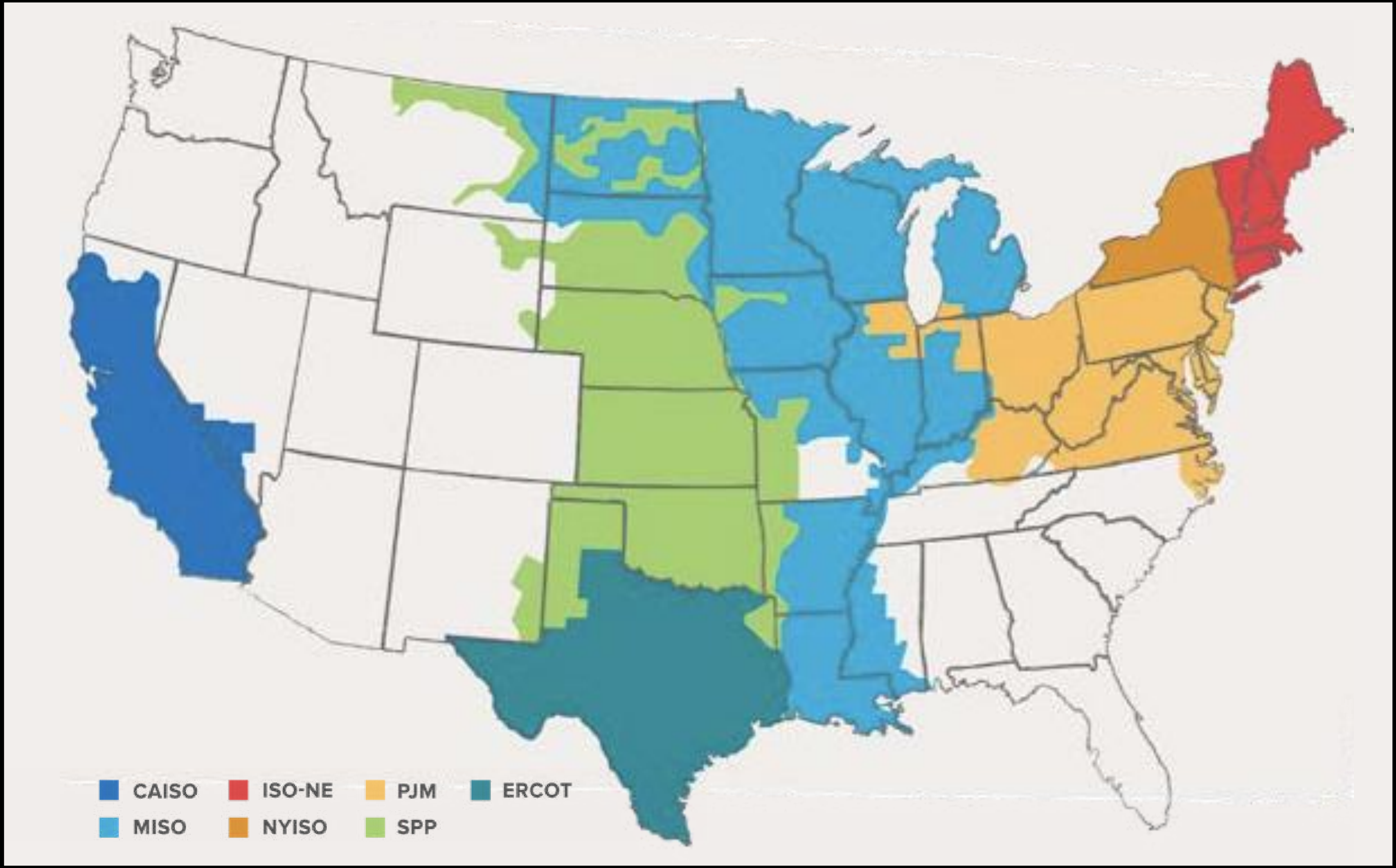
Book > Market

Benefits

ADFIT (See Garrett)

What is Probable?

- ISO/RTO
  - Savings:
    $700M
    $1.4B



What is Probable?

TABLE 1: SUMMARY OF RESULTS

Cost Category	Quantification/Total Impact on Florida Customers	State and Local Government Portion	
		Low Estimate	High Estimate
	Upfront or One-Time Costs		
Generation Stranded Costs[2]	• $10 billion to $12.3 billion • These costs will be experienced even under the proponent's interpretation of the Amendment since all these assets must be transferred to new entities	• $1.1 billion	• $1.4 billion
T&D and Electric Infrastructure Stranded Costs	• The net book value investment in IOUs' T&D assets is $24.3 billion • A substantial portion of this investment could be stranded when IOUs divest their T&D ownership • No other state that has restructured prohibited IOU ownership of T&D • Stranded costs for T&D and other electric infrastructure have not been specifically quantified because there is no precedent for restructuring of this type	• Unknown	• Unknown
Creation of a Wholesale Market and ISO Start-up/RTO Integration Costs	• Start-up costs range from $100 to $500 million • Other costs (e.g., customer education) approximately $20 million • These costs will occur even under the proponent's interpretation of the Amendment since the Amendment specifically calls for the establishment of a market monitor	• Start-up costs of $11.0 million • Other costs (e.g., consumer education) of $20 million	• Start-up costs of $55.0 million • Other costs (e.g., consumer education) of $20 million

[2] Note, stranded costs are typically recovered from electricity customers over a period of years through a "competitive transition charge." For purposes on this analysis they are presented as upfront, one-time costs.

What is Probable?

Support for FIEC [illegible] Impact Statement

Cost Category	Quantification/Total Impact on Florida Customers	State and Local Government Portion	
		Low Estimate	High Estimate
Litigation Costs	• Litigation costs to implement the Constitutional Amendment range from $150 million to $300 million	• $150 million	• $300 million
Total Upfront or One-Time Costs	• $10.1 billion to $13.2 billion	• $1.3 billion	• $1.7 billion
	On-Going Annual Costs or Lost Revenues		
Franchise Fees	• $679.1 million in *annual* local municipality revenues would be eliminated • These costs will occur under the proponent's interpretation of the Amendment since franchises will be eliminated	• $679.1 million per year	• $679.1 million per year
Tax Revenues	• Decrease in *annual* property tax revenues by approximately $129.4 million to $173.8 million • Numerous additional risks related to declines in other state and local taxes, such as gross receipts tax and municipal public service tax • These costs will occur even under the proponent's interpretation of the Amendment since the taxable value of generation-related property will be lower	• $129.4 million per year	• $173.8 million per year
ISO Management and Administrative Costs	• Annual operating costs of $170.0 to $228.0 million • These costs will occur even under the proponent's interpretation of the Amendment since the Amendment specifically calls for the establishment of a market monitor	• $18.7 million per year	• $25.1 million per year
Total On-going Annual Costs or Lost Revenues	• $978.5 million to $1.1 billion per year	• $827.2 million per year	• $878.0 million per year

What is Probable?

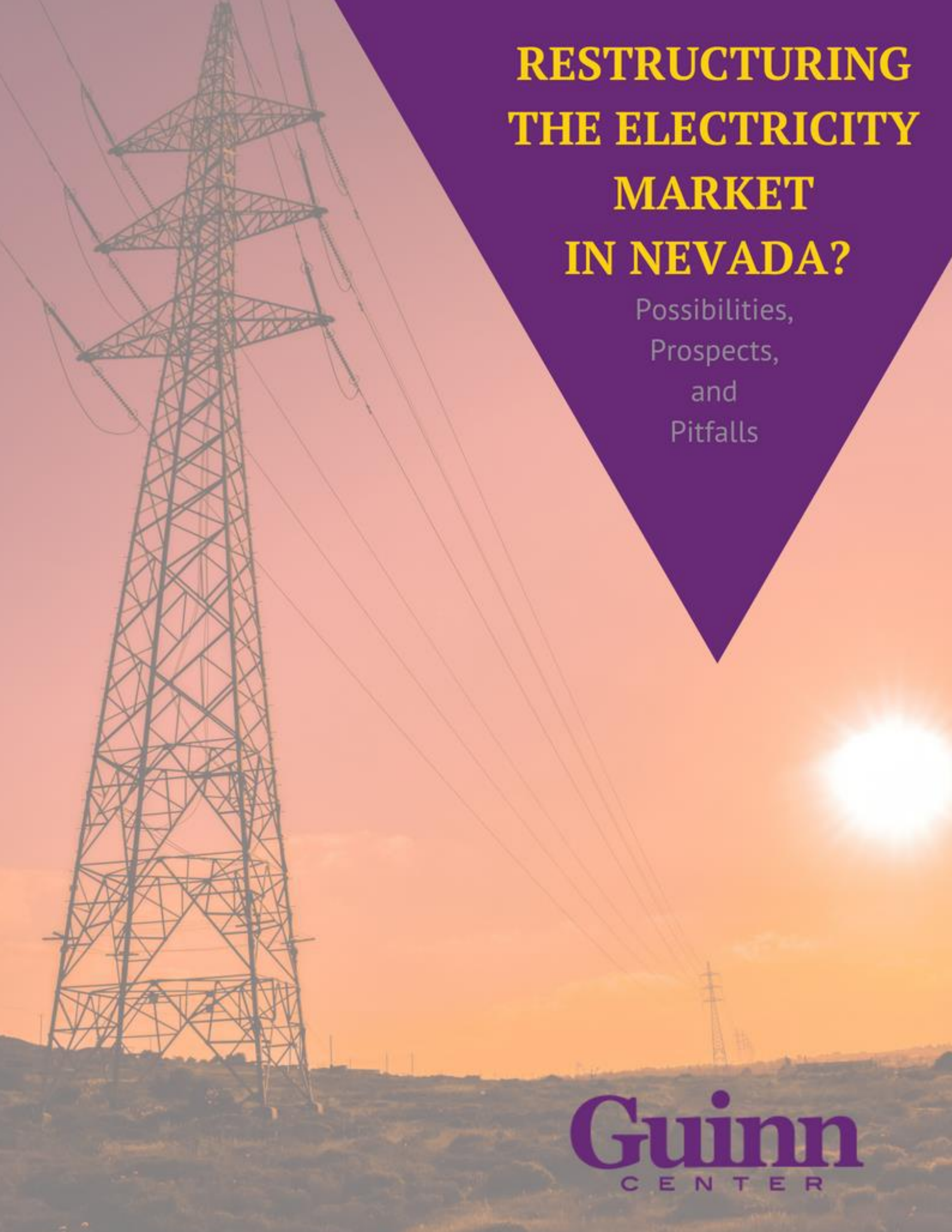
QUESTION 3 – ENERGY CHOICE IN NEVADA: FINANCIAL IMPACT COULD NOT BE DETERMINED

The Fiscal Analysis Division cannot predict when the Legislature and Governor will enact legislation that complies with the Initiative, nor can it predict how the constitutional provisions proposed within the Initiative will be implemented or which state or local government agencies will be tasked with implementing and administering any laws relating to an open, competitive retail electric energy market. Thus, the financial impact relating to the administration of the Initiative by potentially affected state and local government entities cannot be determined with any reasonable degree of certainty.

Under current law, state and local governments, including school districts, may receive revenue from taxes and fees imposed upon certain public utilities operating within the jurisdiction of that government entity, based on the gross revenue or net profits received by the public utility within that jurisdiction. The Fiscal Analysis Division cannot determine what effect, if any, the open, competitive retail electric energy market created by the Legislature and Governor may have on the consumption of electricity in Nevada, the price of electricity that is sold by these public utilities, or the gross revenue or net profits received by these public utilities. Thus, the potential effect, if any, upon revenue received by those government entities cannot be determined with any reasonable degree of certainty.

Additionally, because the Fiscal Analysis Division cannot predict whether enactment of Question 3 will result in any specific changes in the price of electricity or the consumption of electricity by state and local government entities, the potential expenditure effects on those government entities cannot be determined with any reasonable degree of certainty.

Prepared by the Fiscal Analysis Division of the Legislative Counsel Bureau of the Nevada Legislature – August 12, 2016



RESTRUCTURING THE ELECTRICITY MARKET IN NEVADA?

Possibilities, Prospects, and Pitfalls

Guinn
CENTER

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Executive Summary

Background

Question 3: The Energy Choice Initiative (ECI) is a statewide constitutional ballot initiative that will be placed before Nevada's registered voters at the November 6, 2018, General Election. Question 3 seeks to amend the *Nevada Constitution* by adding a new section to its Declaration of Rights regarding the provision of electric utility service in the State. Question 3 reads:

Shall Article 1 of the *Nevada Constitution* be amended to require the Legislature to provide by law for the establishment of an open, competitive retail electric energy market that prohibits the granting of monopolies and exclusive franchises for the generation of electricity?

This policy report summarizes and evaluates the primary arguments made by supporters and opponents of Question 3, which relate to (1) electric rate behavior, and (2) whether a restructured market will promote or hinder the development of renewables in Nevada (see below).

YES on 3: "Energy choice will lower electric bills for all Nevadans."

NO on 3: "Dismantling Nevada's existing electricity system would cost billions of dollars....These costs would be paid for by all Nevadans in the form of higher electricity rates...."

YES on 3: "Energy choice will expand Nevada's clean energy options."

NO on 3: "Threatens Nevada's progress toward a clean energy future."

In addition, we consider additional issues surrounding restructuring, in particular, organized wholesale markets (ISO creation or participation), divestiture/stranded assets, consumer impact, and implementation. While the Guinn Center does not take a position on Question 3, we seek to inform the debate so that Nevadans better understand the issue.

In compiling this Technical Report, the Guinn Center conducted an extensive review of federal energy data and more than two dozen interviews with energy industry experts around the country, and reviewed research documenting the experiences of other states that restructured their electricity markets (and adopted "energy choice"). Following its standard protocol, the Guinn Center distributed drafts of this report to subject matter experts—some of whom support, oppose, or have remained neutral on Question 3—for review. The Guinn Center relies on these subject matter experts to review its reports for accuracy and for an assessment of balanced treatment of the subject.

Given that the evidence we reviewed is comparative and historical, rather than predictive, we cannot demonstrate conclusively that energy choice (Question 3) is either "good" or "bad" for Nevada. That can be known only with the wisdom of hindsight. The Guinn Center notes, however, that the transition to a restructured (or "energy choice") electricity is accompanied by variability in rate behavior, implementation challenges, and, for residential ratepayers, increased uncertainty resulting from heightened exposure to wholesale electric prices.

A Restructured Electricity Market (Energy Choice)

Historically in Nevada, the four components (i.e., generation, transmission, distribution, and retailing) of electricity delivery to the end-user (e.g., residential, business) were bundled together, with the delivery functions coordinated by a vertically integrated electric company, or utility. This means that "…the utility owns all levels of the supply chain" and retains the exclusive right to sell electricity in a designated service territory. In Nevada, the vertically integrated utility is NV Energy.

Question 3 would ***restructure*** the electricity market in Nevada and may require the monopoly electric utility (e.g., NV Energy) to unbundle its services. Restructuring is often referred to as retail choice, energy choice, customer choice and/or direct access. If Question 3 passes, we would expect:

- Monopoly utilities (e.g., NV Energy) likely would no longer manage or be involved in the generation of electricity and would be expected to sell their generation assets (known as "divestiture").
- New (additional) participants could enter the electricity market. These include: (1) independent power producers (IPPs), or owners of power plants and other generation assets; (2) competitive suppliers, which are brokers between the wholesale electric market and customers in the retail market; and (3) an independent system operator (ISO), which manages sales in an organized wholesale market and coordinates generation with the other components of electricity delivery—transmission and distribution—to ensure resource adequacy and reliability.
- Nevada would have to participate in an organized wholesale market. Currently, the monopoly utility (i.e., NV Energy) participates in a **traditional** wholesale market where utilities enter into both short- and long-term bilateral contracts to trade electric power. In contrast, if Question 3 passes, actors would be required to participate in an **organized** wholesale market, which is coordinated by an independent system operator (ISO) or regional transmission organization (RTO).

Summary of Findings

The combination of technological advances (e.g., demand side management, distributed generation), policy and regulatory actions, and the belief that choice would lead to lower electricity costs, led several states to consider restructuring their electricity markets in the mid-1990s and through the early 2000s. To date, 22 states restructured their markets (i.e., energy choice for residential, commercial, and industrial customers), and two states are considering it. Seven states later repealed it (at least, in part), and two to four are currently considering ways to repeal it. We reviewed the experiences of other states, and our conclusions are presented below.

Rate Behavior

- Most studies that evaluate rate behavior use data from the U.S. Energy information Agency (EIA) data. However, electricity rates reflect different inputs including fuel prices, weather, and regulatory costs, among others. As such, comparisons of energy prices over time and across states are challenging, if not impossible. In fact, EIA stated explicitly that its data should not be used for these purposes, describing it as a "proxy" that "does not capture the statewide variation in price determinants" and that any such methodology would result in an "apples-to-oranges" comparison, leading to biased results. Accordingly, we cannot make a conclusive determination as to whether restructuring, all else equal, contributes to rate increases or rate decreases.

- Research suggests that a restructured electricity market may lead to either increases or decreases in electric rates. Evidence reveals the experiences of other restructured states have been uneven; some customers benefit from energy choice, while others encounter adverse effects.

- In a restructured market with energy choice, the wholesale price of natural gas is the most important determinant of customer electricity rates. While wholesale electric costs influence electric rates in both traditionally regulated markets and restructured markets, consumers are exposed more directly to changes and volatility in commodity pricing under restructured markets. When natural gas prices are low, consumers in restructured states—by virtue of their increased exposure to the wholesale market—realize benefits from lower fuel costs. But when they rise, consumers may pay higher electricity bills. Other issues that could influence rates include stranded costs and participation in an organized wholesale market.

- Under current Nevada law, the monopoly utility (NV Energy) cannot profit from fuel and purchased power costs. However, in energy choice states, the state utility regulatory body does not retain its authority over pricing, and the Federal Energy Regulatory Commission (FERC) does not have authority over sales at retail. Under energy choice, the Public Utilities Commission of Nevada likely would no longer be able to able to intervene to protect consumers against higher rates, as that likely would undermine the intent of the initiative petition, which requires that the Nevada Legislature establish "an open, competitive retail electric energy market."

- With the exception of Maine, all states that pursued restructuring (energy choice) implemented some form of rate caps, rate freezes, and/or rate reductions to stabilize markets, protect consumers, and smooth the transition to a fully competitive market.

- Market design efforts used by states to stabilize markets also complicates efforts to evaluate rate behavior after states adopted energy choice: (1) most of the research that showed a link between restructuring and decreased electric rates was published prior to the expiration of rate caps, and to the extent that prices were found to be lower in restructured areas, these results may be skewed by the depressive effects of rate caps, freezes, and reductions; and (2) many states confronted simultaneous expirations in rate caps, freezes, and reductions—when prices became aligned more closely with wholesale costs—and volatility in those very same wholesale electric costs in electricity markets, which either exacerbated the problem or helped mitigate it.

- In short, wholesale electric prices and market design (i.e., rate caps, freezes, and reductions) influence rate behavior, and the effects are amplified in restructured ("energy choice") markets. In some restructured states, competition has not flourished for residential customers as originally intended, and/or many residential customers have experienced electric rate price spikes resulting from the expiration of rate caps and fluctuations in wholesale market energy prices.

Renewable Energy

- Question 3 does not explicitly require that Nevada integrate more renewables onto the grid. Research indicates there is no correlation between restructuring ("energy choice") electricity markets and increased renewables. The type of retail market model in a given state matters less than policy choices, such as a state's Renewable Portfolio Standard (RPS). (Note that voters will consider Question 6 in the 2018 General Election, which seeks to increase the state's RPS from 25 percent by 2025 to 50 percent by 2030.)

- Under a restructured market, the independent system operator (ISO) manages the organized wholesale markets and the auction process. If Question 3 passes, the choice of organized wholesale market/ISO Nevada joins could influence whether Nevada consumes more renewable energy, as the fuel portfolios differ considerably across the proposed markets.

- A related point addresses the issue of net metering, which credits solar energy system owners for the electricity they add to the grid. At present, it is not clear what will happen to net metering customers in Nevada if Question 3 passes. Central to this issue are questions of existing law, the obligations of the incumbent utility (e.g., NV Energy), and the Public Utilities Commission of Nevada's (PUCN) authority under energy or retail electric choice. In 2017, Assembly Bill (AB) 405 was enacted, which established a rate structure for net metering customers. It is not clear that approval of Question 3 would invalidate this preexisting statutory authority. But, if Question 3 passes, NV Energy likely would no longer be involved in the generation of electricity and would not provide retail rates. However, if the measure passes, the Legislature or PUCN, in theory, could enforce net metering rules on a new competitive supplier that wants to participate in the market.

- Increased renewable energy (solar) generation assets may come online regardless of whether Question 3 passes in November 2018.

Consumer Impact

- Irrespective of market structure, the procurement of electricity has different impacts across ratepayer classes. Large commercial and industrial (C&I) customers tend to enjoy lower rates, relative to their residential and small commercial counterparts, under both vertically integrated utilities and energy (retail electric) choice.

- Consumers in states with restructured markets have experienced mixed results. Residential and small commercial consumers, who typically are unfamiliar with the energy choice structure, may be disadvantaged under restructured markets in the absence of strong consumer protection regulations. Across multiple states, many consumers have been enticed by low teaser rates offered by electric suppliers to sign up for variable-rate electricity contracts, but were unaware that their bills could increase at any time, and often did, as market conditions changed.

- The most common consumer complaints are: (1) unknown fees; (2) poor customer service; (3) meter reading; (4) slamming and cramming ("Cramming is the illegal act of placing misleading charges on your bill that you did not agree to. Slamming is the process of switching your energy service to another provider without your permission[.]"); (5) switch hold rules, or the inability to switch retail providers until a back bill is paid in full; and (6) fluctuating prices.

Implementation

- Experience suggests that implementation of a restructured market has not followed a simple, straightforward path (e.g., restructuring the Pennsylvania market was a "16-year process").
- Many states that restructured had to enact multiple pieces of legislation and/or issue regulatory orders to address the unanticipated outcomes and unintended consequences of restructuring; in 2006, Michigan's Public Service Commission, for example, had to issue 40 regulatory orders to "further establish and implement the framework" for its energy choice program. Many implementation hurdles required an expanded role for the government.
- Question 3: The Energy Choice Initiative seeks to restructure Nevada's electricity market through an amendment to the *Nevada Constitution*. In contrast, all other states, with the exception of one, did so through legislation; New York restructured its electricity market through a regulatory order issued by its Public Service Commission.
- The Nevada Legislature allows investor-owned utilities in Nevada to be monopolies, granting the utility exclusive franchise over a designated service territory. This suggests that, historically, electric utility service has been understood as a policy/regulatory issue, not a constitutional one.
- Using the *Nevada Constitution* as a regulatory tool forces the Nevada Legislature to proceed with restructuring. Even if legislators find that restructuring is infeasible, the constitutional imperative takes precedence. Should Nevadans become concerned about the prospects of restructuring, they would have to repeal the constitutional amendment with another constitutional amendment. This would entail circulation of a new petition to obtain the requisite number of signatures to appear on the ballot and then passage in two successive elections.

Conclusion

- In other states that adopted energy choice and restructured their electricity markets, decision-makers subsequently had to intervene to stabilize markets and protect consumers, facilitate competition, and establish new or revise existing regulatory frameworks.
- The experiences of other states suggest that restructuring is a complex and prolonged process that will take time, and only after retail electric choice is realized fully would Nevadans be able to determine if restructuring was the "right" path.

Restructuring the Electricity Market in Nevada?

Possibilities, Prospects, and Pitfalls

Technical Report

Objective

This policy report reviews issues regarding the ballot initiative, Question 3: The Energy Choice Initiative, that registered Nevada voters will consider on November 6, 2018. The subject of Question 3—namely the proposed restructuring of Nevada's electricity markets—is complex. Supporters and opponents of Question 3 are providing data and arguments that appear to conflict with each other. This policy report summarizes and evaluates the primary arguments for and against passage of Question 3: The Energy Choice Initiative.

Specifically, we assess the validity of assertions regarding: (1) the direction of rate behavior—that is, if electricity rates will increase or decrease; and (2) the proposition that energy (retail electric) choice will or will not result in the integration of increased renewable energy onto the grid. In addition, we consider additional issues surrounding restructuring, in particular, organized wholesale markets (ISO creation or participation), divestiture/stranded assets, consumer impact, and implementation.

While the Guinn Center does not take a position on Question 3, we seek to inform the debate so that decision-makers, ratepayers, and voters better understand the issue.

In compiling this policy report, the Guinn Center has conducted an extensive review of existing federal energy data and more than two dozen interviews with energy industry experts around the country, and synthesized research documenting the experiences of others states that restructured their electricity markets (and adopted "energy choice").

I. Introduction

Question 3: The Energy Choice Initiative (ECI) is a statewide constitutional ballot initiative that will be placed before Nevada's registered voters at the November 6, 2018, General Election. Question 3 seeks to amend the *Nevada Constitution* by adding a new section to its Declaration of Rights regarding the provision of electric utility service in the State.[1]

Question 3 reads:

> Shall Article 1 of the *Nevada Constitution* be amended to require the Legislature to provide by law for the establishment of an open, competitive retail electric energy market that prohibits the granting of monopolies and exclusive franchises for the generation of electricity?[2]

Initiative petitions that propose to amend the *Nevada Constitution* require passage by the voters "in two successive elections before [they] can be added to the Nevada Constitution."[3] ECI passed at the 2016 General Election.[4] If a majority of Nevada voters approve the ballot initiative in 2018, the Nevada Legislature and the Governor must enact statutes that set forth implementation for the amendment's provisions by July 1, 2023.[5]

The Nevadans for Affordable Clean Energy Choices Political Action Committee (PAC) circulated the original petition to obtain the requisite number of signatures to appear initially on the 2016 ballot.[6] The PAC characterizes the Energy Choice Initiative (ECI) as follows: the establishment of a new energy policy, the creation of new rights for Nevadans, and the creation of a new mandate for the Nevada Legislature.[7] Pursuant to the initiative petition and amongst other related policy matters, ECI generally would "establish an open, competitive retail electric energy market."[8]

In general, ECI proposes to *restructure* the electricity market in Nevada. Restructuring is defined by the U.S. Energy Information Administration (EIA) as: "The process of replacing a monopoly system of electric utilities with competing sellers, allowing individual retail customers to choose their electricity supplier but still receive delivery over the power lines of the local utility. It includes the reconfiguration of the vertically-integrated electric utility."[9] Restructuring is sometimes referred to as retail choice, energy choice, customer choice, and/or direct access.[a] Simply put, if a majority of voters approved Question 3, retail choice would permit customers in Nevada to purchase electricity from competitive suppliers.[10] It would disallow a single provider from having the exclusive right to sell electricity in a designated service territory, which is permitted under current law in Nevada.

In public messaging about Question 3, supporters and opponents often refer to restructuring as deregulation or re-regulation. However, restructuring should not be construed as deregulation, which is defined by EIA as: "The elimination of some or all regulations from a previously regulated industry or sector of an industry."[b, 11] The ballot measure, Question 3: The Energy Choice Initiative, does not propose to *eliminate* regulation from the preexisting electricity delivery paradigm, but rather requires the Nevada Legislature to adopt a new regulatory framework for a market-based model of retail electric choice. In fact, as we shall discuss throughout this report, new and additional regulations may be necessary to establish and maintain a choice-driven retail electric energy market. Additionally, the term "re-regulation" is not appropriate or accurate, as it refers to the restoration of

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[a] We will use these terms interchangeably.

[b] We only use the terms "deregulation," "deregulating," and "deregulated" when quoting source material directly.

vertical integration after efforts to restructure the electricity market have been suspended or repealed.[c, 12]

The ECI initiative petition contains specific directives to the Nevada Legislature, including, but not limited to:

1) forming open and competitive electricity markets;
2) affording meaningful choices among different [electricity] providers;
3) minimizing economic and regulatory burdens to promote competition and choices in the electric energy market; and
4) eliminating the grant of monopolies and exclusive franchises for the generation of electricity.[13]

In recognition that certain legal, policy, and procedural issues attendant to ECI required input from various interested parties across Nevada on legislative, regulatory, and executive actions for effective and efficient implementation of the initiative—should it pass again in 2018—Governor Brian Sandoval issued Executive Order 2017-03 in 2017 at the outset of the 79th Legislative Session (in February 2017).[14] This Order established the Governor's Committee on Energy Choice (CEC), a 25-member committee of stakeholders drawn from the Nevada Legislature, the Executive Branch, NV Energy, the Public Utilities Commission of Nevada (PUCN), businesses, community organizations, and ratepayers, amongst others.[15]

On June 18, 2018, the CEC delivered its report, as required by the Governor, with findings and recommendations.[16] The report is available on the official website of the Nevada Governor's Office of Energy, Governor's Committee on Energy Choice (*The Governor's Committee on Energy Choice: Draft Report of Findings & Recommendations, July 1, 2018*). The PUCN released a report on April 30, 2018, and included an addendum dated April 29, 2018.[17] The report (*Energy Choice Initiative Final Report: Investigatory Docket No. 17-10001*) and the addendum (*prepared by Commissioner Ann C. Pongracz to supplement the Draft Report in Docket No. 17-10001*) may be accessed through the PUCN's official website.

As a complement to the existing body of information, the Guinn Center has reviewed and analyzed the data and experiences of other states to provide an independent assessment of the primary arguments as presented by those who support Question 3 (Yes on Question 3) and those who oppose Question 3 (No on Question 3). As part of this undertaking, our team has conducted a comprehensive, albeit not exhaustive, analysis of the implications of market restructuring. Along with the primary arguments offered by supporters and opponents of Question 3, which center on rate behavior and renewable energy, this policy report addresses other issues related to retail electric choice, specifically, consumer impact and implementation.

[c] We only use the term "re-regulation" when quoting source material directly.

Our point of departure, which underscores the methodological value in examining the experiences of other states, is the following statement from testimony before the first meeting of the CEC by Josh Weber, Davison Van Cleve, P.C., serving as counsel to the Energy Choice Initiative/Nevadans for Affordable Clean Energy Choices (i.e., Yes on Question 3):

> So, one thing we want to, right off the top, suggest is that the Committee and the Legislature would do well to look carefully at what's happened in other states that have successfully carried out deregulation, and, you know, it's good also to look at those who were unsuccessful. A decade or so ago, there were some attempts at deregulation and customer choice that didn't work out well. In places where it has worked very well, it's been an ongoing evolution. And so we'd like to encourage…the Committee here to talk to experts who have seen it, been through it, and done it…[.][18]

While the Guinn Center neither represents the CEC nor the Nevada Legislature, the advice is very instructive, as an examination of other states' histories with restructuring illuminates the prospects, possibilities, and pitfalls for the Silver State. Were ECI to pass again in November 2018 by a majority of Nevada voters, more than 20 years of "lessons learned" from other states would provide guidance to decision-makers in Nevada. There are commonalities across those states with restructured electricity markets that manifested in comparable outcomes. That these states encountered similar policy questions and regulatory issues as they implemented retail electric choice, while not deterministic for Nevada, lends insight into what the Silver State and its residents may confront should it move forward with restructuring.

A review of the research and experiences of other states collectively reveals that restructuring the electric energy retail market is accompanied by variability in rate behavior, implementation challenges, and, for residential ratepayers, increased uncertainty resulting from heightened exposure to wholesale electric prices. We caution the reader not to interpret the recurrence of these themes as the conveyance of any normative value judgment; insofar as the evidence is comparative and historical, rather than predictive, it does not demonstrate conclusively that energy choice is either "good" or "bad" for Nevada. That can be known only with the wisdom of hindsight.

Methodology

The basis for this report is the following methodology:

1) Interviews with approximately two dozen industry experts, academics, federal officials, organized wholesale market representatives, and current/former utility regulators nationwide;

2) A review of legislation, utility regulation reports, and official electric shopping websites in restructured states;

3) A study of secondary sources from industry leaders (including competitive suppliers), the federal government, academia, and journalists;

4) Testimony/exhibits from the Governor's Committee on Energy Choice (CEC) and the Legislative Committee on Energy; and

5) Consultation of the CEC report and the PUCN report, which are available publicly.

The Guinn Center did not review any private or proprietary data that had not been evaluated previously by an independent, third party. Following its standard and well-established protocol that mirrors the practice used by academic researchers and national policy institutes, the Guinn Center distributed drafts of this report to subject matter experts, some of whom support, oppose, or have remained neutral on Question 3: The Energy Choice Initiative. The Guinn Center relies on these subject matter experts to review its reports for accuracy and for an assessment of balanced treatment of the subject.[d]

The following pages are organized into four parts. Section II provides a primer on electricity delivery and market restructuring, which establishes a foundation for the discussion to follow. Section III assesses the validity of the arguments promulgated by those who support Question 3 and those who oppose it, with an emphasis on rate behavior and renewable energy. Section IV addresses some additional issues related to restructuring, specifically, organized wholesale markets (ISO creation or participation), divestiture/stranded assets, consumer impact, and implementation. Section V concludes with a synthesis of the material presented herein. We recap our findings below.

Findings

This policy report finds the following:

Rate Behavior

- Most studies that evaluate rate behavior use data from the U.S. Energy information Agency (EIA) data. However, electricity rates reflect different inputs including fuel prices, weather, and regulatory costs, among others. As such, comparisons of energy prices over time and across states are challenging, if not impossible. In fact, EIA stated explicitly that its data should not be used for these purposes, describing it as a "proxy" that "does not capture the statewide variation in price determinants" and that any such methodology would result in an "apples-to-oranges" comparison, leading to biased results. Accordingly, we cannot make a conclusive determination as to whether restructuring, all else equal, contributes to rate increases or rate decreases.

- Research suggests that a restructured electricity market may lead to either increases or decreases in electric rates. Evidence reveals the experiences of other restructured states have been uneven; some customers benefit from energy choice, while others encounter adverse effects.

[d] The Guinn Center board of directors includes several individuals who have a direct interest in the outcome of Question 3. Here, we note that the Guinn Center board does not interfere with, direct, or review the research and analysis of the staff. Drafts of Guinn Center policy reports are reviewed by external subject matter experts who read for accuracy, relevance, and appropriate and fair treatment of the subject matter.

- In a restructured market with energy choice, the wholesale price of natural gas is the most important determinant of customer electricity rates. While wholesale electric costs influence electric rates in both traditionally regulated markets and restructured markets, consumers are exposed more directly to changes and volatility in commodity pricing under restructured markets. When natural gas prices are low, consumers in restructured states—by virtue of their increased exposure to the wholesale market—realize benefits from lower fuel costs. But when they rise, consumers may pay higher electricity bills. Other issues that could influence rates include stranded costs and participation in an organized wholesale market.
- Under current Nevada law, the monopoly utility (NV Energy) cannot profit from fuel and purchased power costs. However, in energy choice states, the state utility regulatory body does not retain its authority over pricing, and the Federal Energy Regulatory Commission (FERC) does not have authority over sales at retail. Under energy choice, the Public Utilities Commission of Nevada likely would no longer be able to able to intervene to protect consumers against higher rates, as that likely would undermine the intent of the initiative petition, which requires that the Nevada Legislature establish "an open, competitive retail electric energy market."
- With the exception of Maine, all states that pursued restructuring (energy choice) implemented some form of rate caps, rate freezes, and/or rate reductions to stabilize markets, protect consumers, and smooth the transition to a fully competitive market.
- Market design efforts used by states to stabilize markets also complicates efforts to evaluate rate behavior after states adopted energy choice: (1) most of the research that showed a link between restructuring and decreased electric rates was published prior to the expiration of rate caps, and to the extent that prices were found to be lower in restructured areas, these results may be skewed by the depressive effects of rate caps, freezes, and reductions; and (2) many states confronted simultaneous expirations in rate caps, freezes, and reductions—when prices became aligned more closely with wholesale costs—and volatility in those very same wholesale electric costs in electricity markets, which either exacerbated the problem or helped mitigate it.
- In short, wholesale electric prices and market design (i.e., rate caps, freezes, and reductions) influence rate behavior, and the effects are amplified in restructured ("energy choice") markets. In some restructured states, competition has not flourished for residential customers as originally intended, and/or many residential customers have experienced electric rate price spikes resulting from the expiration of rate caps and fluctuations in wholesale market energy prices.

Renewable Energy

- Question 3 does not explicitly require that Nevada integrate more renewables onto the grid. Research indicates there is no correlation between restructuring ("energy choice") electricity markets and increased renewables. The type of retail market model in a given state matters less than policy choices, such as a state's Renewable Portfolio Standard (RPS). (Note that voters will consider Question 6 in the 2018 General Election, which seeks to increase the state's RPS from 25 percent by 2025 to 50 percent by 2030.)

- Under a restructured market, the independent system operator (ISO) manages the organized wholesale markets and the auction process. If Question 3 passes, the choice of organized wholesale market/ISO Nevada joins could influence whether Nevada consumes more renewable energy, as the fuel portfolios differ considerably across the proposed markets.
- A related point addresses the issue of net metering, which credits solar energy system owners for the electricity they add to the grid. At present, it is not clear what will happen to net metering customers in Nevada if Question 3 passes. Central to this issue are questions of existing law, the obligations of the incumbent utility (e.g., NV Energy), and the Public Utilities Commission of Nevada's (PUCN) authority under energy or retail electric choice. In 2017, Assembly Bill (AB) 405 was enacted, which established a rate structure for net metering customers. It is not clear that approval of Question 3 would invalidate this preexisting statutory authority. But, if Question 3 passes, NV Energy likely would no longer be involved in the generation of electricity and would not provide retail rates. However, if the measure passes, the Legislature or PUCN, in theory, could enforce net metering rules on a new competitive supplier that wants to participate in the market.
- While retail suppliers may promise "100% Renewable" contracts, that does not mean that more renewable energy is delivered onto the grid, only that the company must purchase Renewable Energy Credits (RECs) to comply with the terms of the contract offered or the RPS in the state. A high RPS may dissuade suppliers from entering the market, as RECs can be costly.
- Increased renewable energy (solar) generation assets may come online regardless of whether Question 3 passes in November 2018.

Consumer Impact

- Irrespective of market structure, the procurement of electricity has different impacts across ratepayer classes. Large commercial and industrial (C&I) customers tend to enjoy lower rates, relative to their residential and small commercial counterparts, under both vertically integrated utilities and energy (retail electric) choice.
- Consumers in states with restructured markets have experienced mixed results. Residential and small commercial consumers, who typically are unfamiliar with the energy choice structure, may be disadvantaged under restructured markets in the absence of strong consumer protection regulations. Across multiple states, many consumers have been enticed by low teaser rates offered by electric suppliers to sign up for variable-rate electricity contracts, but were unaware that their bills could increase at any time, and often did, as market conditions changed.
- The most common consumer complaints are: (1) unknown fees; (2) poor customer service; (3) meter reading; (4) slamming and cramming ("Cramming is the illegal act of placing misleading charges on your bill that you did not agree to. Slamming is the process of switching your energy service to another provider without your permission[.]"); (5) switch hold rules, or the inability to switch retail providers until a back bill is paid in full; and (6) fluctuating prices.

Implementation

- Experience suggests that implementation of a restructured market has not followed a simple, straightforward path (e.g., restructuring the Pennsylvania market was a "16-year process").
- Many states that restructured had to enact multiple pieces of legislation and/or issue regulatory orders to address the unanticipated outcomes and unintended consequences of restructuring; in 2006, Michigan's Public Service Commission, for example, had to issue 40 regulatory orders to "further establish and implement the framework" for its energy choice program. Many implementation hurdles required an expanded role for the government.
- Question 3: The Energy Choice Initiative seeks to restructure Nevada's electricity market through an amendment to the *Nevada Constitution*. In contrast, all other states, with the exception of one, did so through legislation; New York restructured its electricity market through a regulatory order issued by its Public Service Commission.
- The Nevada Legislature allows investor-owned utilities in Nevada to be monopolies, granting the utility exclusive franchise over a designated service territory. This suggests that, historically, electric utility service has been understood as a policy/regulatory issue, not a constitutional one.
- Using the *Nevada Constitution* as a regulatory tool forces the Nevada Legislature to proceed with restructuring. Even if legislators find that restructuring is infeasible, the constitutional imperative takes precedence. Should Nevadans become concerned about the prospects of restructuring, they would have to repeal the constitutional amendment with another constitutional amendment. This would entail circulation of a new petition to obtain the requisite number of signatures to appear on the ballot and then passage in two successive elections.

II. Electricity Delivery and Market Restructuring: A Primer

This section serves as an "Electricity 101," laying the groundwork for the analyses to follow in Section III and Section IV. It begins with a discussion of the components of electricity delivery: generation, transmission, distribution, and retailing/customer service. To understand what would change through the restructuring process, our readers first must have a sense of the current market structure. As such, we explain the terms "vertical integration" and "natural monopoly," as well as describe the role of the current regulatory authority. Next, we outline the basis for restructuring, which include technological advances and legislative/regulatory changes at the federal level. We also present a map of residential choice and non-choice states, along with those that have repealed choice for residential customers; this should provide the reader with an idea of the geographic concentration of retail electric choice in the United States.

We conclude the section with an overview of institutions and market design that tend to accompany restructuring and contrast these with the structure that exists under traditional regulation (e.g., a utility such as NV Energy). Under restructuring, there are new ways of doing business and new participants in the market, including: (1) independent power producers (IPPs), or owners of power plants and other generation assets; (2) competitive suppliers, which are brokers between the wholesale electric market and customers in the retail market; and (3) an independent system operator (ISO), which manages sales in an organized wholesale market and coordinates generation with the other components of electricity delivery—transmission and distribution—to ensure resource adequacy, and, accordingly, reliability.[e] These features of restructured markets are important to understand, as the differences between them and a traditional market structure are considerable.

The Components of Electricity Delivery

Electricity delivery is the process of moving produced electric power to an end-use customer, such as a residence or a business. It consists of four components: generation, transmission, distribution, and retailing (sometimes called customer service).[19] The EIA definitions for the first three components are useful in establishing an agreed-upon understanding of terms throughout this report:[f]

Generation: "The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in kilowatthours [kWh]."[20] The forms of energy used to generate electric energy are varied and usually include natural gas, coal, solar, geothermal, and wind.

Transmission: "The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery

[e] Nevada currently does not participate in an organized wholesale market but would need to join one or establish its own, were Question 3 to pass, as discussed later in this section.

[f] This report will emphasize the first three components, as they are the most salient to a discussion of retail electric choice, though we will address the fourth component, where necessary.

to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer."[21]

Distribution: "The delivery of energy to retail customers." The distribution system is: "The portion of the transmission and facilities of an electric system that is dedicated to delivering electric energy to an end-user."[22]

Retailing/Customer Service: While there is no official definition, retailing encompasses the administrative costs associated with electricity delivery, such as metering, billing, and customer service, amongst others.[g, 23]

In short, power plants—regardless of whether they use natural gas, coal, or renewables—generate electric power, which is delivered over transmission lines to electrical substations; from there, electricity is carried over the distribution system to customers.[24] The transmission and distribution system may be referred to as the grid.[25] Others term this the "wires," and we will use both interchangeably when referring to transmission and distribution in concert with one another.

Historically, the four components (i.e., generation, transmission, distribution, and retailing) were bundled together, with the delivery functions coordinated by a vertically integrated electric company, or utility.[26] This means that "…the utility owns all levels of the supply chain – generation; transmission of bulk, high-voltage power; and distribution of lower-voltage power to end users. However, utilities also purchase electricity in power purchase agreements (PPAs) with independent generators, and they send power over transmission lines owned by other organizations."[27]

Vertical Integration, Natural Monopoly, and Regulatory Authority

The basis for vertical integration was a recognition by Congress that, by virtue of providing a public service, utilities had a "natural monopoly" over a given service area.[28] Monopoly, or the presence of a single seller in a market with multiple buyers, is viewed by classical economists as inefficient insofar as it can restrict choice and drive up prices.

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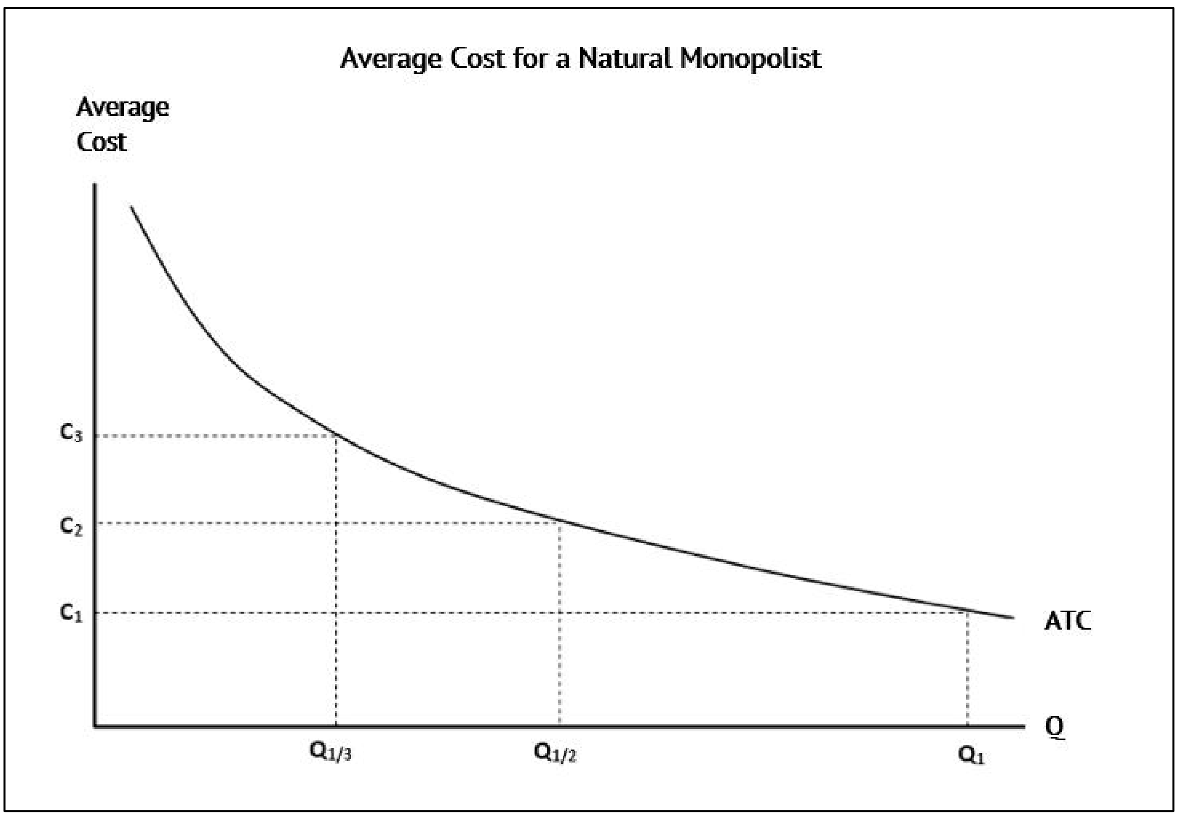
[g] The three main customer classes are: residential, commercial, and industrial. The residential sector is defined as: "An energy-consuming sector that consists of living quarters for private households." (*Source*: U.S. Department of Energy, U.S. Energy Information Administration. "Glossary: R." Available: https://www.eia.gov/tools/glossary/index.php?id=R.) The commercial sector is defined as: "An energy-consuming sector that consists of service-providing facilities and equipment of businesses; Federal, State, and local governments; and other private and public organizations, such as religious, social, or fraternal groups. The commercial sector includes institutional living quarters. It also includes sewage treatment facilities." (*Source*: U.S. Department of Energy, U.S. Energy Information Administration. "Glossary: C." Available: https://www.eia.gov/tools/glossary/index.php?id=C.) The industrial sector is defined as: "An energy-consuming sector that consists of all facilities and equipment used for producing, processing, or assembling goods. The industrial sector encompasses the following types of activity manufacturing (NAICS codes 31-33); agriculture, forestry, fishing and hunting (NAICS code 11); mining, including oil and gas extraction (NAICS code 21); and construction (NAICS code 23)." (*Source*: U.S. Department of Energy, U.S. Energy Information Administration. "Glossary: I." Available: Industrial sector: https://www.eia.gov/tools/glossary/index.php?id=I.)

The concept of a natural monopoly is distinct, however. Where there is a natural monopoly, the government may grant an entity, such as a utility, exclusive franchise over a designated service territory, as it can supply electricity at a lower cost than any other market entrant. Expressed in economic terms, "It defines a single firm that is technologically able to serve an entire market at a lower cost than multiple firms could. Natural monopoly is associated with extraordinary economies of scale and of scope, often coupled with high fixed costs that serve as barriers to entry. These factors, when present, can allow a single big firm to serve multiple customers at a lower cost than multiple firms serving the same market."[29] The concept of natural monopoly is depicted graphically in Figure 1.[30]

Figure 1 shows that, under conditions of natural monopoly, when there is one seller in the market (Q_1), it has an average cost C_1, which is lower than the costs for two sellers in the market ($Q_{1/2}$; average cost C_2) or three sellers in the market ($Q_{1/3}$; average cost C_3). If an industry is considered a natural monopoly, the expectation is that average costs for the end-use customer would be lower than what could be provided in a competitive market.[31]

Figure 1. **Average Cost for a Natural Monopolist**



As of 2016, there were nine electricity service providers in Nevada with service territories designated by the PUCN: seven cooperative associations (Harney Electric Cooperative, Inc.; Mt. Wheeler Power, Inc.; Plumas-Sierra Rural Electric Cooperative, Inc.; Raft River Rural Electric Cooperative, Inc.; Surprise Valley Electrification Corporation; Valley Electric Association, Inc.; and Wells Rural Electric

Company) and two subsidiaries of one investor-owned electric utility (Nevada Power Company and Sierra Pacific Power Company, doing business as NV Energy).[32] There is also a municipal power authority, City of Fallon, and two public utility districts, Lincoln County and Overton.[h, 33] NV Energy supplies electricity to 1.25 million end-users (residential, commercial, and industrial customers) over a near-46,000 square-mile service territory.[34] With gas and electric combined, NV Energy provides service to 90 percent of Nevada's residential, industrial, and commercial customers.[35]

The Public Utilities Commission of Nevada (PUCN) is responsible for regulation of investor-owned utilities in Nevada. According to the PUCN website:

> The Nevada Legislature has passed laws which allow investor-owned utilities in Nevada to be monopolies. A monopoly exists when there is no competition for a product or service. In the case of utility companies, this means that there is only one provider of a utility service in a given area, or service territory. In return for being granted the right to be sole provider in a service territory, the investor-owned utility submits to price and service quality regulation by the PUCN. Regulation of investor-owned utilities exists because the investor-owned utility is motivated by the pursuit of a reasonable profit. Regulation ensures that the utility provides reliable service at just and reasonable rates. In other words, the PUCN's role is to prevent utilities from price gouging and/or providing substandard service because their customers have no available alternative provider of service.[36]

The Basis for Restructuring

Over time, the idea that electric utilities constituted a natural monopoly has been called into question. "Significant technological improvements…provided for deployment of larger and more efficient combined cycle natural gas-fired power plants, supplanting previous utility reliance on less-efficient single-cycle fossil-fired steam units," which contributed to the idea that the generation component could be subject to competition.[37] Specifically, "…the efficient scale of a power plant is now sufficiently small so as to allow effective competition among generators."[38] Improvements to electricity transmission equipment allowed for the delivery of power over long distances.[39] This meant that geographic siting of generation assets and transmission lines in tandem—that is, physical proximity—became less salient for the purposes of electricity delivery, which translated into the belief that the generation component was not necessarily constrained by the natural monopoly concept.

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[h] Question 3: The Energy Choice Initiative theoretically applies to all electricity providers in the State, not just NV Energy, as the ballot initiative grants a right to each person, business, et cetera, to choose the provider of its electric utility service. See: Nevada Secretary of State. 2016. "Statewide Ballot Questions: To Appear on the November 8, 2016 General Election Ballot: Initiative Petition - Constitutional Amendment: THE ENERGY CHOICE INITIATIVE." Page 42. Available: http://nvsos.gov/sos/home/showdocument?id=4434.

Concurrently, federal legislative and regulatory changes supplied institutional mechanisms that helped facilitate competition.[i] With respect to regulation, the Federal Energy Regulatory Commission (FERC) issued a series of rules, including Orders 888, 889, and 2000, which mandated that utilities open their transmission lines "to outside, unregulated suppliers on a non-discriminatory basis."[40] These orders, collectively, also established independent system operators (ISOs) and regional transmission organizations (RTOs)—discussed below with regard to organized wholesale markets—which required the creation and operation of wholesale competitive electric markets across all utilities on a fair and transparent basis.[41]

Many rationales for retail electric choice have been offered over the years. But the primary one is captured perhaps most comprehensively by the Distributed Energy Financial Group (DEFG) LLC, a management consulting firm specializing in energy that produces the *Annual Baseline Assessment of Choice in Canada and the United States* (ABACCUS) report, which scores "U.S. states and Canadian provinces with respect to their efforts and achievements in the promotion of retail competition in the electric sector."[42] DEFG views retail choice as a three-step process, beginning with competition on price, then moving through to competition on service, and then finally to competition through innovation.[43] The U.S. General Accounting Office (GAO) outlined the goals of restructuring as lower prices and a more diverse, innovative array of retail services, both of which might be achieved through competition.[j, 44] Several reports point out that choice may give customers control over the types of retail products they prefer, such as "green" electricity.[45]

The combination of technological advances (e.g., demand-side management, distributed generation), policy and regulatory actions, and the belief that choice would lead to lower electricity costs, paved the way for several states to consider the viability of restructuring their electricity markets in the mid-1990s and through the early 2000s.[k] As one report notes, "Restructuring actions vary by region and by state, but they are typically characterized by the 'unbundling' of ownership and regulation of electricity generation, transmission, distribution, and sales, with large variations in how restructuring is implemented across regions and states."[46] In practice, the vast majority of states that pursued

[i] The Public Utility Regulatory Policies Act (PURPA) of 1978 required utilities to purchase energy produced by all qualified electric facilities (QFs) in their territory through long-term contracts. The Energy Policy Act (EPAct) of 1992 introduced power suppliers into the market and permitted the interconnection of new generating plants (not just QFs) to the regional wholesale transmission system, allowing sales at the wholesale level. (*Source*: Reishus Consulting, LLC. "Electric Restructuring in New England – A Look Back." Prepared for New England States Committee on Electricity (NESCOE). December 21, 2015. Available: http://nescoe.com/resource-center/restructuring-dec2015/.)

[j] The U.S. General Accounting Office was redesignated the U.S. Government Accountability Office in 2004; the acronym GAO was retained. (*Source*: Frederick M. Kaiser. 2008. "GAO: Government Accountability Office and General Accounting Office." Congressional Research Service. Available: https://fas.org/sgp/crs/misc/RL30349.pdf.)

[k] Per the U.S. Environmental Protection Agency (EPA), "Distributed generation refers to a variety of technologies that generate electricity at or near where it will be used, such as solar panels and combined heat and power." (*Source*: U.S. Environmental Protection Agency. "Distributed Generation of Electricity and its Environmental Impacts." Available: https://www.epa.gov/energy/distributed-generation-electricity-and-its-environmental-impacts.)

restructuring did so by unbundling generation only—that is, they opened up the generation component to competitive supply—while reserving the right to exclusive franchise over the wires (transmission and distribution) to the utilities. Unbundled generation typifies the retail electric choice model in the United States.

Residential Retail Electric Choice, Non-Choice, and Suspended/Repealed States

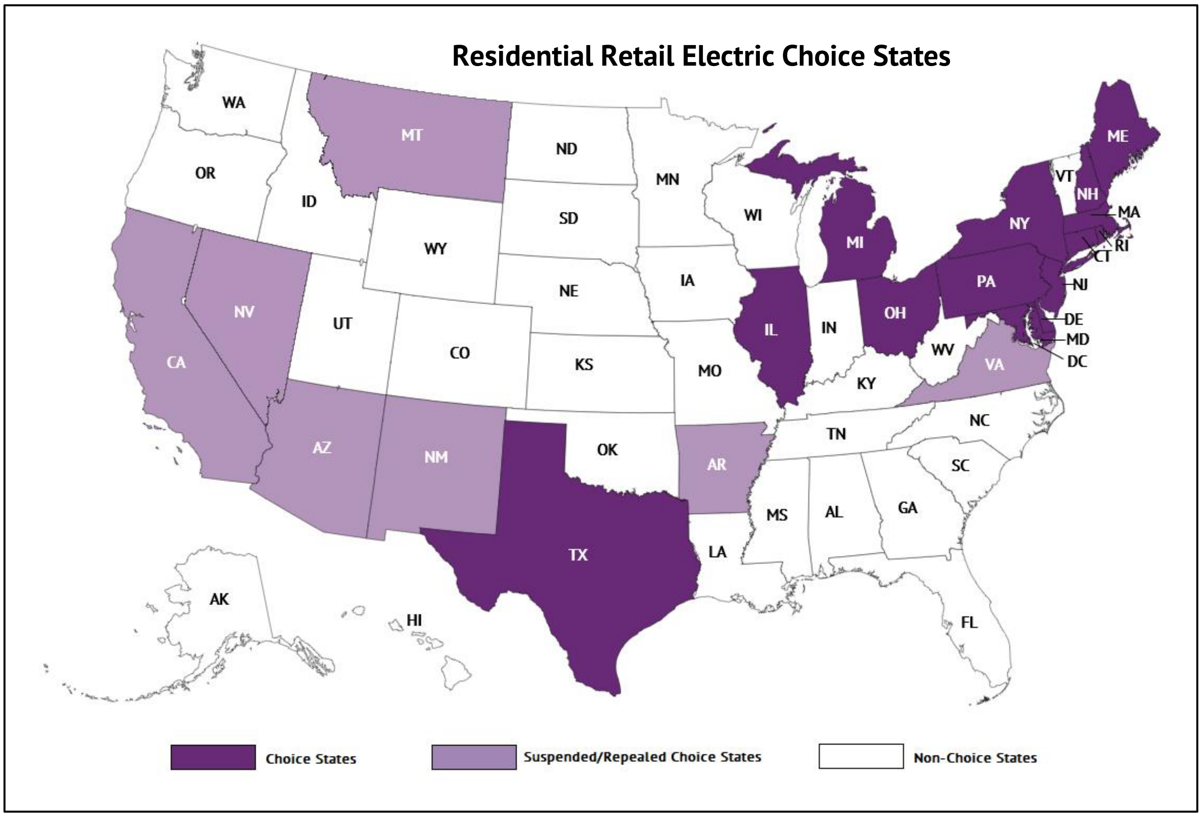
Figure 2A presents a map of states that provide or have provided retail electric choice to residential ratepayers. The figure displays "Choice States," which are the current states that permit residential retail electric choice, "Non-Choice States," which are the current states that do not permit residential retail electric choice, and "Suspended/Repealed Choice States," which are the states that permitted residential retail electric choice but do not currently do so by virtue of suspension or repeal.[l] As

[l] Effective Date of Suspension or Repeal: **Arizona**: January 27, 2004. *Source* (for year): ASU Energy Policy Innovation Council. 2013. "An Introduction to Restructuring of Electricity Markets." Arizona State University. Available: https://energypolicy.asu.edu/wp-content/uploads/2012/03/AZ-restructuring-status_-final.pdf. *Source* (for reference to actual date per Arizona Court of Appeals): Ariz. Ct. App. 2004. "Phelps Dodge et al. v. Az. Corp. Comm'n: CV 01-0068." Available: http://www.azcourts.gov/Portals/89/opinionfiles/CV/CV010068.pdf. **Arkansas**: February 21, 2003. *Source*: Arkansas State Legislature. 2003. "HB1114 - An Act to Repeal Chapter 19 of Title 23 and to Reform Electric Utility Regulation." Available: http://www.arkleg.state.ar.us/assembly/2003/R/Pages/BillInformation.aspx?measureno=HB1114. **California**: September 20, 2001. *Source*: Channele Carner. 2003. "Status of State Electric Industry Restructuring Activity — as of February 2003 —." U.S. Department of Energy, U.S. Energy Information Administration. Available: http://large.stanford.edu/publications/coal/references/docs/restructure.pdf. **Montana**: October 1, 2007. *Source*: Montana Legislature. 2007. "Detailed Bill Information: HB 25, Generally Revise Electric Industry Restructuring Laws." Available: http://laws.leg.mt.gov/legprd/LAW0210W$BSIV.ActionQuery?P_BILL_NO1=25&P_BLTP_BILL_TYP_CD=HB&Z_ACTION=Find&P_SESS=20071. **Nevada**: Before July 1, 2003. *Source*: Channele Carner. 2003. "Status of State Electric Industry Restructuring Activity — as of February 2003 —." U.S. Department of Energy, U.S. Energy Information Administration. Available: http://large.stanford.edu/publications/coal/references/docs/restructure.pdf. **New Mexico**: April 8, 2003. *Source*: New Mexico Legislature. 2003. "SB718: Public Utility Transition Cost Recovery." Available: https://www.nmlegis.gov/Legislation/Legislation?Chamber=S&LegType=B&LegNo=718&year=03. **Virginia**: December 31, 2008. *Sources* (allowed retail choice for residential customers until the expiration or termination of capped rates): HB 3068 (§ 56-577(4)) at: Virginia's Legislative Information System. 2007. "Chapter 888." Available: http://lis.virginia.gov/cgi-bin/legp604.exe?071+ful+CHAP0888; and Virginia Legislative System. 2007. "HB 3068: Electric Utility Service; Advances Scheduled Expiration of Capped Rate Period. Summary as Enacted with Governor's Recommendation (April 11, 2007)." Available: http://lis.virginia.gov/cgi-bin/legp604.exe?071+sum+HB3068. *Sources* (companion bill for dates of advancing of scheduled rate caps): "The bill [SB 1416] advanced the scheduled expiration of the capped rate period from December 31, 2010, to December 31, 2008." See: James M. Van Nostrand. 2008. "Constitutional Limitations on the Ability of States to Rehabilitate Their Failed Electric Utility Restructuring Plans." *Seattle University Law Review*. Vol. 31, No. 3. Page 624. Available: https://digitalcommons.law.seattleu.edu/cgi/viewcontent.cgi?article=1058&context=sulr. For a summary of SB 1416, see: Virginia Legislative System. 2007. "SB 1416 Electric Utility Service; Advances Scheduled Expiration of Capped Rate Period. Summary as Enacted with Governor's Recommendation (April 11, 2007)." Available: http://lis.virginia.gov/cgi-bin/legp604.exe?071+sum+SB1416.

Figure 2A indicates, current residential retail electric choice states tend to be concentrated in the Northeast and Upper Midwest, with Texas as the exception in the Intermountain West. Vermont is the only state in New England to retain a traditionally regulated electric utility structure, and Virginia is the only state to repeal residential retail electric choice on the East Coast. Outside of Arkansas, the other states to suspend or repeal their residential direct access (energy choice) programs are located in the western United States, including Arizona, California, Montana, Nevada, and New Mexico. (See the discussion of implementation in Section IV, which contains timelines of restructuring in the applicable states.)

[k] (cont'd): California/Michigan: There is no consensus as to whether California and Michigan should be considered residential retail electric choice states. Some reports count just one (or the other), while some count both. The Guinn Center treats California as a "Suspended/Repealed Choice State," as the California Public Utilities Commission (CPUC) suspended retail choice on September 20, 2001. Neither the California State Legislature nor the CPUC has overturned the ruling. The state does permit Community Choice Aggregation (CCA), which "allows for communities to join together to purchase electricity on behalf of their community members." *Source*: CalCCA. "CalCCA Advocates for Community Choice in California." Available: https://cal-cca.org/about/#top.) Pursuant to Assembly Bill (AB) 117 in 2002, see: California Public Utilities Commission, Staff White Paper. 2017. "Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework." Available: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail Choice White Paper 5 8 17.pdf. While California's CCAs are "an alternative to the incumbent utility," they do not operate in a retail electric choice context (see: Nicolas Chaset, California Public Utilities Commission, Chief of Staff to Commission President Michael Picker. "Customer and Retail Choice in California." Exhibit Prepared for the Governor's Committee on Energy Choice, May 10, 2017. Available: http://energy.nv.gov/uploadedFiles/energynvgov/content/Programs/TaskForces/2017/Agenda item 4 - California Presentation.pdf). (Regarding partial access, "In October 2009, Governor Arnold Schwarzenegger signed into law, Senate Bill 695, which provided for a limited reopening of the DA [direct access] market for only non-residential customers beginning in April 2010. Subsequently, the CPUC issued two Decisions, D.10-03-022 and D.10-05-039 which established Annual Load Caps for a phased reopening over a 4 year period and an Overall Load Cap of 9,520 GWh." See: PG&E. "Direct Access Electric Service." July 1, 2018. Available: https://www.pge.com/en_US/business/services/alternatives-to-pge/electric-services/direct-access-electricity/direct-access-electricity.page.) Michigan technically permits residential retail electric choice, though "no more than 10 percent of an electric utility's average weather-adjusted retail sales for the preceding calendar year may take service from an alternative electric supplier at any time." This means that "[c]urrently, no licensed alternative electric suppliers are marketing or enrolling residential customers." (See: Michigan Public Service Commission. "Electric Customer Choice Frequently Asked Questions for Customers." Available: https://www.michigan.gov/mpsc/0,4639,7-159-16377_17111-42899--,00.html.) While Michigan's residents do not have access to retail electric choice currently, the law theoretically permits it, and, as such, the Guinn Center treats it as "Choice State."

Figure 2A. Residential Retail Electric Choice States



Some states have partial access to choice (including but not limited to those that have suspended or repealed residential retail electric choice), as shown in Figure 2B.[m] Among these states is Nevada, which allows nongovernmental commercial or industrial end-use customers with average annual loads (i.e., demand) of one megawatt (mW) or more in the service territory of an electric utility to procure energy from an alternative supplier; in Nevada, they must pay an exit fee to the utility to do so and continue to pay the utility for wires service.[n, 47]

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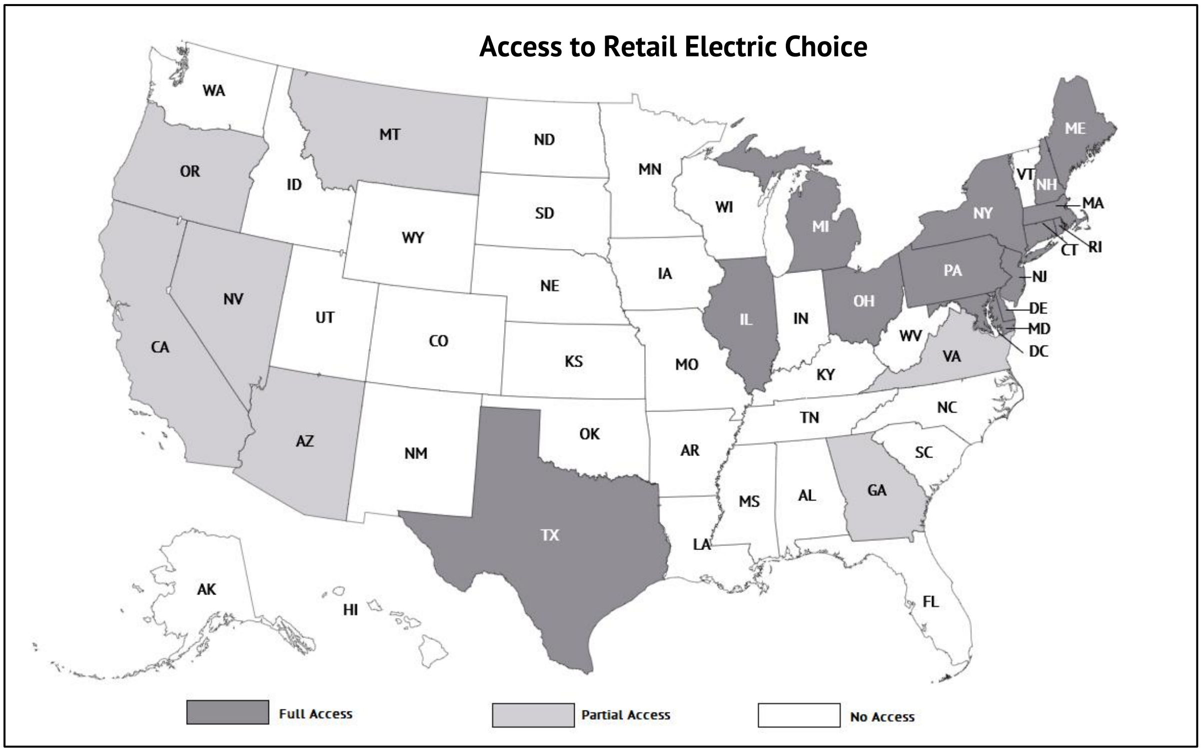
[m] Partial Access to Retail Choice/Load-Permitted Access to Retail Choice: All states with residential retail electric choice have full access to choice (i.e., all ratepayer classes). Of the states that suspended/repealed choice, Arizona, California, Montana, Nevada, and Virginia have load-permitted access to retail choice. (*Source*: Wayne Kuipers and Laura Chappelle. "Electricity Customer Choice Out-Performs Traditional Monopoly." *Utility Dive*. August 23, 2016. Available: https://www.utilitydive.com/news/electricity-customer-choice-out-performs-traditional-monopoly-1/424986/.) Georgia permits retail choice for those customers with more than 900 kW of load, as does Oregon for certain large electricity customers. (*Source*: Mathew J. Morey and Laurence D. Kirsch [Christensen Associates Energy Consulting LLC]. 2016. "Retail Choice in Electricity: What Have We Learned in 20 Years?" Prepared for Electric Markets Research Foundation. Available: https://sites.hks.harvard.edu/hepg/Papers/2016/Retail_Choice_in_Electricity_for_EMRF_Final.pdf.) Following the preceding footnote, Michigan is treated as a full-access state.

[n] Exit fee: the mechanism to ensure that remaining, captive customers are not burdened by the exit of another customer. Cite: Guinn Center conversation with industry expert. This process is referred to as 704B in Nevada.

Figure 2B. Access to Retail Electric Choice



Vertical Integration vs. Retail Electric Choice: Institutions and Market Design

How does retail electric choice work in practice? Unbundling the generation component of electricity delivery means that the vertically integrated utility theoretically would sell its generation assets—which can include power plants and long-term power purchase agreements (PPAs), or contracts between electricity generators and electricity buyers for additional sources of power—through a process known as divestiture. Under a choice model, this may be understood as structural separation.[48] An exhibit presented to the CEC by Jackie Roberts, a consumer advocate from West Virginia, stated that, "Utilities must divest of generation to protect consumers. Without divestiture or full structural separation of utility generation, retail competition is difficult if not impossible to implement."[49]

Question 3 does not require divestiture explicitly.[50] However, as one industry expert explained to the Guinn Center, it might be inferred: in order to afford meaningful choices among different providers" and "to promote competition and choices," if the utilities were to retain control over generation assets, it would contravene the spirit of the initiative petition.[51] That is, retail electricity suppliers could not compete in the market were the utilities able to retain exclusive control over generation assets.

With regard to transmission and distribution, the Energy Choice Initiative (Question 3) allows for broad legislative discretion over implementation by delegating authority to the Nevada Legislature over the design of the competitive retail electric energy market. Of particular note is language stating that "[t]he Legislature need not provide for the deregulation of transmission or distribution of electricity in order to establish a competitive market consistent with this Act."[52] This language has been interpreted to mean that while the Nevada Legislature must restructure the generation component of electricity delivery, it may determine whether or not transmission and distribution should be subject to restructuring, as well.[o] However, the conventional understanding is that transmission and distribution would continue to constitute a natural monopoly.[p, 53]

Our operating assumption, based on extensive testimony and interviews, is that if Question 3 were to pass in November 2018 by a majority of registered Nevada voters, divestiture of generation assets would be required, and NV Energy would retain its ownership of transmission and distribution of electric energy. (See Section IV for a detailed discussion of divestiture and stranded assets.)[q]

As previously noted, under a vertically integrated utility structure, the utility coordinates all components of electricity delivery and is regulated by a public utilities commission. The utility determines resource adequacy to meet demand and thus is able to deliver service with reliability.[54] If its generation assets and power-purchase agreements (PPAs) are insufficient at a given time, such as when demand peaks during hot summers in southern Nevada or cold winters in northern and rural Nevada, the utility can enter into bilateral contracts with generators for short-term purchases.[55]

Retail electric choice would introduce a new way of doing business into Nevada's electricity market. Primary participants in this new system are: (1) independent power producers (IPPs), which own generation assets, such as power plants; and (2) competitive suppliers. The responsibility for electricity supply thus is separated into retail suppliers and IPPs, each of which plays a crucial, albeit distinct, role in the market.

An independent power producer is defined by EIA as: "A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and that is not an electric utility."[56] IPPs may construct new generation facilities, enter into long-term PPAs, and/or own generation assets previously held by the utility but sold through divestiture.

In a restructured market, a retail supplier (or electric supplier) is a critical participant. It "…is a company that sells the energy that the utility delivers."[57] Electric suppliers typically are licensed by the state, and under energy choice, customers can choose amongst suppliers in the market.[58] These

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[o] The CEO of NV Energy, Paul Caudill, has signaled to the CEC that the utility would consider transitioning to a wires-only company if that is what the State wants. See: Paul Caudill, NV Energy, CEO. "Statement to the Governor's Committee on Energy Choice During Question and Answer Session with Pat Wood (Texas Presentation)." May 10, 2017. Available: http://nvleg.granicus.com/MediaPlayer.php?publish_id=6c23a1ae-35cf-11e7-b343-f04da2064c47.

[p] As is true in all states but Michigan, per our research. (See pages 43 and 69 for details on Michigan's "hybrid structure.")

[q] The incumbent utility's assets become "stranded" through the divestiture process. Assets may be sold for a loss, resulting in stranded costs, or they may be sold for a gain, resulting in negative stranded costs (i.e., stranded benefits).

retail suppliers act as brokers between the end-use customer and independent power producers (IPPs).

In sum, under retail electric choice, a single entity would no longer manage the generation component of the supply chain.

In theory, retail electric choice affords the wholesale electric market greater prominence than under a traditional model of electricity delivery, in which utilities typically own a considerable amount of generation assets. While vertically integrated utilities participate in wholesale markets, these markets—known as traditional wholesale markets or "bilateral" wholesale markets—are used for both short- and long-term transactions to trade electric power.[59] A short-term transaction is entered into by a utility and a generation facility for the procurement of power when the utility is confronted with resource inadequacy; a long-term transaction is a power purchase agreement (PPA).

Retail electric choice requires participation in an organized wholesale market, which is coordinated by the aforementioned independent system operator (ISO) or regional transmission organization (RTO). (ISOs and RTOs are functionally equivalent, but, for consistency, we will use the term ISO hereafter.)[60] Organized wholesale markets are where both short- and long-term energy power transactions are conducted.[61] All states with retail competition participate in organized wholesale markets, and some states that have not restructured participate in organized wholesale markets, as well (i.e., their utilities do). See, for example, Minnesota, as shown in Figure 3 (page 22).

While this may sound similar to the way traditional wholesale markets function, the process is quite different under a restructured market. Under retail electric choice, PPAs are permitted. However, in large part, electricity prices are set through an auction process characterized by competitive bidding.[62] Specifically, in organized wholesale markets after a state has embraced retail choice, pricing is determined through auction-based market pricing, real-time ("spot market") pricing, and bilateral contracts.[63] The following should be noted:

> …when power is generated, it becomes part of the wholesale electricity market where it is traded like any other commodity by the players granted permission to operate in that specific market. These electricity grids, also known as Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs) are considered to be *interconnected*, which allows for broad-based trading of electricity across geographies.[64]

Independent power producers (IPPs) operate in the organized wholesale market, and electric suppliers broker the transactions between the IPPs and the end-use customer.[65] The latter can be understood as an intermediary between the wholesale electric market and the retail market, as most ratepayers normally do not conduct transactions directly with the IPPs.[66] (The exception may be large commercial and industrial ratepayers, depending on the laws of the state in which they are located.)[r,67]

As such, there are several reasons why states who restructure their electricity market must participate in the organized wholesale market/ISO:

1) The multiplicity of actors in a restructured market, including retail suppliers and IPPs, precludes traditional approaches to energy procurement. In other words, the presence of many buyers and sellers necessitates a market structure that allows competition to thrive.[68]

2) In the absence of the vertically integrated utility acting to ensure reliability, or that supply is sufficient to meet demand, a central coordination body, such as an ISO, must assume this function.[69] The ISO "oversees the process" in that it "predicts hourly demand" and "selects the winning bids."[70]

3) The ISO combines transmission operations with market operations to maintain grid reliability and serves as a market operator to dispatch transmission to maintain voltage and frequency (i.e., balancing and grid reliability services).[71]

4) Purchases in wholesale markets are made over various time frames, such as year-ahead, month-ahead, days-ahead, day-ahead, and real-time.[72] Generally, vertically integrated utilities operating in traditional wholesale markets participate in all but the day-ahead market and real-time market.[73] NV Energy joined the western Energy Imbalance Market (EIM), which provided access to the real-time market.[s, 74] Nevada's participation in the real-time market likely would be "grandfathered in" under retail electric choice, but the day-ahead market, which is a key feature of an organized wholesale market, cannot be accessed without membership in an ISO.[75] One ISO executive speaks to the importance of the day-ahead market in noting, "The day-ahead market allows buyers and sellers to hedge against price volatility in the Real Time Energy Market by locking in energy prices before the operating day."[76]

5) Under retail electric choice, smaller retail providers may enter the market to serve various end-use customers. Given their size, they may have a smaller fraction of the load (i.e., demand), but they would not be able to function well in the absence of participation in an organized wholesale market, as they would not secure good prices at smaller quantities.[77] Thus, lack of access to an organized wholesale market could dampen retail market entry or spur retail market exit.

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[r] The average end-use customer in a restructured state who selects a retail supplier enters into a contract with said provider and is billed for electric supply by that entity, either through a consolidated bill provided by the wires company or in two separate bills (one for supply and one for wires service and administrative costs). The structure of billing is determined by the laws of the state in question.

[s] "The California ISO's western Energy Imbalance Market (EIM) is a real-time bulk power trading market…[.]" See: Western Energy Imbalance Market. "About." Available: https://www.westerneim.com/Pages/About/default.aspx.

As will be addressed in greater detail in Section IV, Nevada seemingly has three options with regard to organized wholesale markets: creation of its own organized wholesale market as an ISO (e.g., NV-ISO); membership in the Southwest Power Pool (SPP); or participation in the California Independent System Operator (CAISO). However, discussions of a regional grid are underway already, irrespective of the outcome of Question 3: The Energy Choice initiative.[78] NV Energy's joining the EIM signals a potential move in that direction. The CAISO membership pricing estimates outlined in Section IV, notably, are for NV Energy, not retail electric choice, specifically. And Valley Electric Association, Inc. (VEA), "a member-owned electric cooperative headquartered in Pahrump, Nevada," that "provides service to more than 45,000 people within a…6,800-square-mile service area located primarily along the California-Nevada border," "became the first out-of-state utility to join the California Independent System Operator Corporation (CAISO)" in 2013.[79]

Given the intricacies of organized wholesale markets, an additional regulatory layer has been deemed necessary to regulate the exercise of market power: "Every ISO market operates with FERC-approved market power controls, implemented by FERC-mandated independent market monitors, including price caps and auction market offer mitigation."[t, 80] That is, FERC prohibits market manipulation. However, while it regulates rates and services for electric transmission and electric wholesale power sales, FERC does not have statutory authority over sales of electric energy to end users (i.e., sales at retail).[u, 81] It should be noted, however, that, along with the PUCN, FERC already exerts some regulatory power over NV Energy: for example, "[i]n today's market in Nevada, wholesale energy sales – including NV Energy's sales of its excess supply – are subject to FERC's oversight for market power; FERC authorizes sales at market- or cost-based rates based on whether owner has concentrated ownership in the market."[82]

Section IV outlines the opportunities for organized market participation, along with related costs and time frames were ECI to pass in 2018, but it may be helpful here for the reader to have a visual sense of the ISOs based in the United States and Canada. Figure 3 provides such a map.[83]

There are many more dimensions to retail electric choice, but this foundation should serve as context for the analysis to follow. In the next section, we examine the validity of the arguments put forth by supporters of Question 3 and those who oppose it.

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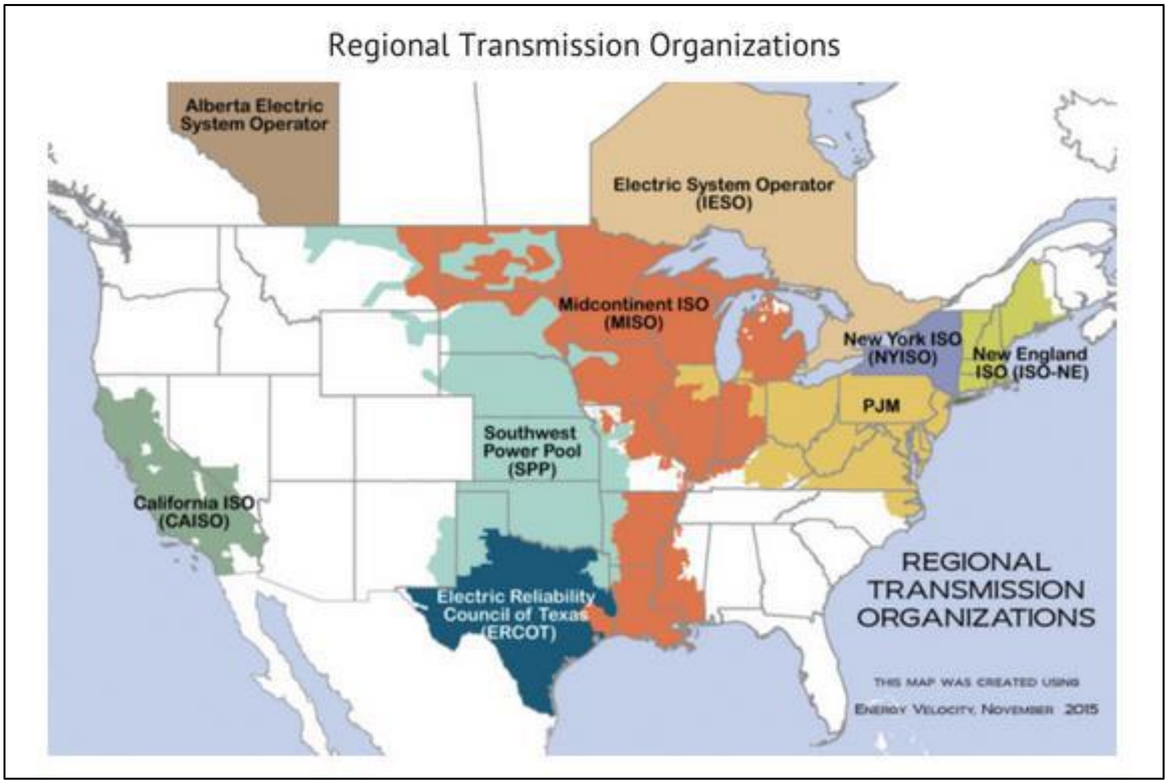
[t] Note that Texas's independent system operator, the Electric Reliability Council of Texas (ERCOT), is regulated by the state, not FERC, in restructured areas. On ERCOT as an ISO, see: ERCOT. "About ERCOT." Available: http://www.ercot.com/about. On state regulation of FERC, see: Philip R. O'Connor, Ph.D., and Erin M. O'Connell-Diaz. 2015. "Evolution Of The Revolution: The Sustained Success Of Retail Electricity Competition." Available: https://yesquestion3.com/wp-content/uploads/2018/05/Massey_Evolution-of-Revolution.pdf.

[u] In the earlier sub-section on vertical integration, natural monopoly, and regulatory authority, we addressed the current role of the Public Utilities of Commission of Nevada (PUCN). It is unknown how it its responsibilities would change under restructuring, as that would be determined by the Nevada Legislature were Question 3 to pass in November 2018. We will discuss this further in Section IV, in the sub-section on implementation.

Figure 3. Regional Transmission Organizations



III. Primary Arguments For and Against ECI: Rate Behavior and Renewable Energy

This section evaluates the primary arguments for and against Question 3: The Energy Choice Initiative (ECI), specifically, those related to rate behavior and renewable energy. The discussion on rate behavior indicates that restructuring is correlated with increases in electric rates *and* decreases in electric rates. Notably, both supporters and opponents of Question 3 use the same data to support their findings. We argue that the conflicting results are a function of the limitations of the data itself, which should not be used to infer causation, as the data is not comparable across states – or even within states. Restructuring cannot be isolated from other factors, such as fuel prices, weather, regulatory costs, and more, all of which contribute to end-user electric rates. In fact, wholesale electric prices and policy decisions about market design have been far more deterministic in shaping rate behavior, the effects of which are amplified in restructured markets. Our examination of other states' experiences with rates demonstrates that some customers have benefited from retail electric choice, while others have encountered adverse effects.

In the discussion on renewable energy, we find that there is no relationship between restructuring and renewable energy. The type of retail market model in a given state matters less than policy choices, such as a state's Renewable Portfolio Standard (RPS), and the willingness of some entity to invest significantly in renewable generation assets. Arguments that favor retail electric choice as a pathway to more renewables typically fail to consider the auction process in organized wholesale markets, as the variability of renewable energy can mean that the independent system operator (ISO) may choose not to use those assets. The RPS can act as a deterrent in a competitive market, as suppliers typically must purchase Renewable Energy Credits (RECs) to maintain compliance; (RECs are paper transactions that are not necessarily related to actual renewable generation, and they can be cost-prohibitive).

Market structure aside, both NV Energy (the incumbent utility) and Switch (a technology infrastructure corporation) have committed to the construction of one gigawatt (gW) of solar projects. Increased renewable energy generation assets may be expected to come online, regardless of whether Question 3 passes in November 2018. Rather, the choice of organized wholesale market/ISO, were Question 3 to pass and the State decided to join a preexisting ISO, could influence whether Nevada consumes more renewable energy, as the proposed markets' fuel portfolios differ considerably.

Rate Behavior in States with Restructured (Energy Choice) Electricity Markets

Text Box 1. Rate Behavior Arguments (from Official Websites)[v, 84]

YES on 3: "Energy choice will lower electric bills for all Nevadans."
NO on 3: "Dismantling Nevada's existing electricity system would cost billions of dollars....These costs would be paid for by all Nevadans in the form of higher electricity rates...."

What one often hears in the debate over retail electric choice in Nevada is "will" statements regarding rates. That is, retail choice *will* lower electric bills, or retail choice *will* increase electricity rates. Which claim is true?

Our research finds that there is evidence to support claims on both sides. And, interestingly, the vast majority of analyses use the same data source. How, then, can we reconcile these differences, given the contradictory findings?

We submit the following: (1) the data used to argue that restructuring causes electric prices to increase or decrease should not be used for those purposes; and (2) we cannot make a conclusive determination as to whether restructuring, all else equal, contributes to rate increases or rate decreases. However, our analysis of the experiences of other choice states does suggest that restructuring exposes ratepayers to the imperfections and challenges of the wholesale electric market, lending to heightened uncertainty around rate behavior.

This section is organized as follows: first, we present annual average retail electricity prices for 2017, which is intended to be a starting point for the discussion; second, we summarize macro-level research on restructuring and electric prices; third, we address data and analytical limitations; and fourth, we document state-specific outcomes that affirm the issues raised in the third sub-section.

Annual Average Retail Price of Electricity

Table 1 presents U.S. Energy information Agency (EIA) data on the annual average retail price of electricity for the Intermountain West states in 2017, by end-use sector (see Appendix B for the table of all 50 states).[85] Electricity prices are usually highest for residential and commercial consumers because it costs more to distribute electricity to them; industrial consumers use more electricity and

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[v] The complete set of arguments from Yes on Question 3 and No on Question 3 is delineated here in the order presented on each website. **Yes on Question 3**: "More jobs; Energy choice will lower electric bills for all Nevadans. (Competition is good. The more choices you have, the easier it is for you to go to a lower cost option when rates increase.); Energy choice will expand Nevada's clean energy options; More choice: Right now, NV Energy is a monopoly and our only choice for electricity." (For "Yes on Question 3," see: Yes on 3: The Energy Choice Initiative. "Get the Facts." Available: https://yesquestion3.com/facts/.) | **No on Question 3**: "Locks a risky experiment into Nevada's Constitution; Leaves implementation to the legislature and courts; Could give California politicians & Federal Government more control over Nevada's electricity system; Would cost Nevada consumers and taxpayers billions; Threatens Nevada's progress toward a clean energy future." (For "No on Question 3," see: No on 3. "Get the Facts." Available: https://noon3.com/get-the-facts/.)

can receive it at higher voltages, so supplying electricity to these customers is more efficient and less expensive (the price of electricity to industrial customers is generally close to the wholesale price of electricity).[86] The EIA data presented in Table 1 provides only a baseline of retail prices of electricity so the reader may have a sense of rate pricing around the country. Note that annual averages are useful in smoothing out seasonal variation but do not capture point-in-time snapshots.[w]

Table 1. **Annual Average Retail Price of Electricity (¢/kWh), Intermountain West States (2017)**

Annual Average Retail Price of Electricity (¢/kWh), Intermountain West States (2017)				
	Residential	Commercial	Industrial	All Sectors
Arizona	12.50	10.58	6.45	10.71
California	18.24	15.89	12.87	16.14
Colorado	12.13	9.95	7.29	9.94
Nevada	**12.00**	**7.98**	**6.13**	**8.76**
New Mexico	12.92	10.27	6.01	9.64
Texas	11.18	8.31	5.49	8.55
Utah	11.04	8.74	6.12	8.66
United States	12.90	10.68	6.91	10.54

Temporal and spatial variation are endemic to the retail pricing of electricity, given the number and type of inputs that influence rates, rendering intrastate, cross-state, and historical comparisons unfounded. These can include, amongst others, fuel prices, weather, and regulatory costs, as we detail further in the sub-section on data and analytical limitations.

Here, we reference the following assertion from the official ECI (Yes on Question 3) comment to the Governor's Committee on Energy Choice (CEC) on the PUCN report in April 2018:

> ...[A] discussion of national averages is not helpful. States have dramatically different electricity economies, a point acknowledged by the [PUCN] Report. It makes no sense to compare Nevada to eastern states (or California) that are in factually dissimilar circumstances. It is like saying that Nevada is sunnier than Oregon, or warmer than Washington - of course it is. The fact that Nevada has lower electricity prices than New York, California, Massachusetts and other high-

[w] The official ECI reply comment presented to the CEC on the PUCN report is critical of annual price metrics, noting that EIA's *Monthly Energy Review* with data from January of 2018 was available at the time of the PUCN's writing (see: Tamara Beatty Peterson, Esq., and Jon Wellinghoff, Esq. "Motion for Leave to Submit Reply Comments of Nevadans for Affordable Clean Energy Choices (Before the Public Utilities Commission of Nevada: Docket No. 17-10001)." Presented as an Exhibit to the Governor's Committee on Energy Choice, May 9, 2018. Available: http://energy.nv.gov/uploadedFiles/energynvgov/content/Programs/TaskForces/2017/Motion re Reply Comments FINAL.pdf). That more recent data is available is not an inaccurate statement, particularly as the PUCN relied on 2016 averages; in fact, the May 2018 EIA *Monthly Energy Review* includes data average retail prices of electricity for February of 2018. (See: U.S. Department of Energy, U.S. Energy Information Administration. "June 2018: Monthly Energy Review." Available: https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.) However, it is not clear that this data is available by state. Furthermore, were it available, we believe that monthly snapshots are problematic, as it would be no more fair to compare, say, Nevada to Massachusetts in February than would be the reverse in July.

cost states where utilities are saddled with difficult to maintain systems and costs of outdated or shut down nuclear plants - among a multiplicity of other factors - should come as no surprise to anyone…[.][87]

Restructuring and Electric Prices: Brief Summary of Research Findings

A. Evidence for Lower Rates

As noted previously, the evidence on the effect of restructuring on electric prices is mixed and inconclusive. The author of one discussion paper stated:

> The evidence simply does not support critics' claims that there have been dramatic price increases in restructured states relative to states that have maintained more traditional forms of regulation….there is no clear pattern in the restructuring status of the states that have seen the greatest increases in retail prices since the mid-1990s. Among the 28 states in which some form of restructuring was implemented, 10 (plus the District of Columbia) experienced increases in average retail prices from 1995 to 2006 that outpaced the national average and 18 states had increases (or even decreases) below the national average. Among the non-restructured states, 11 had price increases above the national average and 11 had below average price increases.[88]

The discussion paper cites several analyses that support the conclusion that restructuring has been beneficial to consumers, including the following: a 2006 report that used EIA state-level data from 1970-2003, which found that retail competition decreases price, with a price effect of about 5 to 10 percent; a 2007 report that used annual average rates, based on EIA data, for 1990-2004 and 1998-2004, which found that restructuring in the mid-Atlantic and New York "produced benefits in the range of $.50 to $1.80/MWh equivalent to a total of $430 million to $1.3 billion per year"; and others that showed price reductions, one of which asserted that consumer savings amounted to around $34 billion from restructuring over a seven-year period.[89]

A report available on the official ECI (Yes on Question 3) website, which uses EIA data, states that, "As a group, Customer Choice Jurisdictions outperformed Monopoly States on price, with average prices increasing less than inflation in competitive markets and far exceeding inflation under monopoly regulation."[90] Another report, which also relies on EIA data, finds that: (1) between 2008 and 2015, half of the restructured states enjoyed price decreases, while just three non-restructured states experienced the same; (2) Compound Average Growth Rate (CAGR) was higher in non-restructured states (3.07 percent) than in restructured states (2.49 percent); and (3) in Michigan, which has tweaked its legislation such that residential retail electric choice technically is allowed by law but currently does not exist in practice, had consumers been given access to the same market-based rates as Illinois, they would have paid $11.3 billion less between 2009 and 2015.[x, 91]

[x] On the current status of residential retail electric choice in Michigan, see: Michigan Public Service Commission. "Electric Customer Choice Frequently Asked Questions for Customers." Available: https://www.michigan.gov/mpsc/0,4639,7-159-16377_17111-42899--,00.html.

In testimony before the CEC, John Hanger, former Secretary of Planning and Policy and Pennsylvania PUC Commissioner, asserted the following: (1) residential and commercial customers in Philadelphia and Pittsburgh pay 40 percent to 56 percent less (in real or inflation-adjusted dollars) than they did in 1996; (2) the average statewide electricity price is at the national average, not "well above it"; and (3) residential customers saved $818 million in 2016 as a result of retail competition.[y, 92]

B. Evidence for Higher Rates

On the other hand, another body of evidence suggests that restructuring has led to increased electric prices in those states that transitioned to a choice model. Many of these studies also use EIA data to argue that restructuring (or transition to "energy choice") contributed to rate increases:

> Of the 11 states and the District of Columbia (D.C.) that have effectively restructured their electricity markets and allow "free market" competition, electricity prices have gone up over four times faster, after restructuring than before restructuring, relative to U.S. electricity prices. Delaware, Maine, New York, Oregon, Rhode Island and the D.C. have extremely significant electricity price increases and are extremely less efficient, after their electric utilities restructure. Massachusetts and Texas have very significant electricity price increases and are very less efficient, after their electric utilities restructure. Connecticut, Maryland, New Hampshire, New Jersey have no significant relative price increases, pre-and-post restructuring; however, these four states retain substantial price suppression regulation, through re-regulation of their electricity marketplaces. No effectively restructured electric utility state is statistically more efficient.[93]

A study on restructuring in the Texas market, using EIA data for 2002-2014, indicates that Texans in restructuring-exempt (or non-choice) areas have paid lower residential electric rates compared to their counterparts in restructured (or choice) areas.[z, 94] Moreover, another report shows that "Texans

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[y] The basis for these findings appear to be a report titled, "A Case Study of Electric Competition Results in Pennsylvania: Real Benefits and Important Choices Ahead," co-authored by Christina Simeone and John Hanger. The authors used EIA data, citing several datasets therein. However, it is not clear whether the findings regarding electricity prices rely entirely, somewhat, or not at all on this data. See: Christina Simeone and John Hanger. "A Case Study of Electric Competition Results in Pennsylvania: Real Benefits and Important Choices Ahead." Kleinman Center for Energy Policy, University of Pennsylvania. October 28, 2016. Available: https://kleinmanenergy.upenn.edu/sites/default/files/proceedingsreports/A Case Study of Electric Competition Results in Pennsylvania_0_0.pdf.

[z] Texas might have offered an interesting "natural experiment" to examine the effects of restructuring, as not all areas in the state are subject to restructuring. San Antonio and Austin, for example, receive electricity service from served by municipally-owned utilities or electric cooperatives, while other cities and towns are outside the boundaries of the grid service area. Ideally, this would allow for a quasi-experimental analysis, since an intrastate comparison might permit assessment of restructuring that is not compromised by variation across states. However, retail electric choice is available to 90 percent of the load in Texas, which would make the validity of the findings limited by the uneven distribution of retail electric choice. And, as we shall see, even intrastate comparisons are limited by the nature of the EIA data. On retail electric choice availability to 90 percent of the load in Texas, see: Philip R. O'Connor, Ph.D., and Erin M. O'Connell-Diaz. 2015. "Evolution Of The Revolution: The Sustained Success Of Retail Electricity Competition." Available: https://yesquestion3.com/wp-content/uploads/2018/05/Massey_Evolution-of-Revolution.pdf.

living in deregulated [choice] areas would have saved nearly $25 billion dollars in lower residential electricity bills from 2002 through 2014, had they paid the same average prices during that period as Texans living outside deregulation [non-choice]. This 'lost savings' amounts to more than $5,100 for a typical household."[95] The report goes on to find, though, that the difference between the two areas has been converging since 2011, with the percentage differential the smallest in 2014 since the inception of restructuring.[96]

In sum, the macro-level research findings point in contradictory directions. On the one hand, there is evidence to support claims that restructuring (retail choice) has resulted in lower electricity prices. On the other, researchers have found that restructuring has contributed to increased electricity prices. With respect to these rate-specific findings, there is one commonality: reliance on EIA data. The next section addresses the problems with this data source for the purpose of evaluating the effect of retail electric choice on rate behavior, along with other analytical issues.

Data and Analytical Limitations

A. Electricity Rate Data Issues

As the previous sub-section noted, the vast majority of research studies use EIA data to reach their conclusions about the efficacy (or lack thereof) of retail electric choice. There are two primary reasons we can identify that may explain the tendency toward reliance on the EIA data: (1) EIA is an agency housed in the U.S. Department of Energy (DOE); it "collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment."[97] It is an "official" federal source that vets data in accordance with uniform guidelines and practices, reinforcing its validity. (2) The information is standardized and is provided for each state, suggesting that statewide comparisons are practicable.

Initially, the Guinn Center, too, intended to use EIA data to conduct an independent analysis of the effects of restructuring on electric pricing. The objective was to determine the extent to which our results conformed with the preexisting research: would they support one side or the other, or would our results be as mixed? However, in conversations with their experts, EIA stated explicitly that its data should not be used for these purposes, describing it as a "proxy" that "does not capture the statewide variation in price determinants" and that any such methodology would result in an 'apples-to-oranges' comparison, leading to biased results."[aa, 98]

EIA's reasoning is sound, as we will detail below. But first, it is necessary to understand exactly what is available in its electricity prices data. EIA-861 contains information on "average price by state by

[aa] The EIA website states, "Electricity prices can be difficult to determine, as they depend on the customer's rate structure, which can differ greatly from company to company. EIA does not directly collect retail electricity rates or utility tariffs. However, using data collected on revenues and kilowatt hours sold to each customer group (residential, commercial, and industrial), EIA calculates average retail revenue per kilowatt hour as a proxy for retail electricity prices." See: U.S. Department of Energy, U.S. Energy Information Administration. "Residential Electricity Prices Are Rising." September 2, 2014. Available: https://www.eia.gov/todayinenergy/detail.php?id=17791.

provider" and is reported for each end-use sector (i.e., residential, commercial, industrial, transportation, other, and total) for 1990-2016.[99] With the shift to retail competition, EIA began to include line items for full-service providers (retail sales to customers who purchase energy and delivery from the same utility, in restructured and non-restructured states, with the exception of Texas, in which customers in restructured areas must purchase from a competitive supplier); restructured retail service providers (sales of energy and delivery, combined, to customers who use retail choice); energy-only providers (sales of energy to customers who use retail choice); and delivery-only service (sales of delivery to customers who use retail choice).[100]

Setting the issue of annual averages aside, which has already been discussed, the dataset itself limits the capacity for analysis. While generation and delivery (i.e., the wires) are disaggregated for restructured providers, the same is not true for full-service providers. Even an intrastate comparison becomes impossible without equivalent measures for generation and wires service. However, were that data available, it still would be inherently problematic for two reasons: (1) it would only afford an appraisal of default service (i.e., Standard Offer Service, or SOS) relative to competitive service in a given state, but because each falls under different regulatory schemes with variation in built-in costs, we could not ascertain the "true" price of electricity for either; and (2) it would not permit cross-state comparisons, regardless, as the mismatched regulatory frameworks within any given state and across states, in combination with other pricing influences that differ by state, do imply an "apples-to-oranges" statistical endeavor.[bb]

We present three sample bills from across the nation to illustrate the above. The first two are from Connecticut: Figure 4A displays a sample bill from the utility in which the customer has maintained default service with that entity but is poised to switch to a competitive supplier, and Figure 4B displays a sample bill for a Connecticut resident that receives its generation from a competitive supplier.[101] Figure 5 is a sample bill from NV Energy.[102]

As Figures 4A and 4B show, while there are commonalities across the two bills—both have generation services and transmission charges—different costs are built into the two bills. The customer with default service pays for "Decoupling Adjustment," "Pension Tracker and Earnings Sharing," and "CTCleanEnergyOptions," while the customer of the competitive supplier does not; conversely, the former does not pay for the "Revenue Adjustment Mechanism Distribution" and the "Adjustment Charge," while the latter does pay for these. These bills exemplify the differences in types of costs incurred by ratepayers in a single state, depending on whether he or she stayed with the full-service provider or switched to a retail supplier, thus demonstrating the problem with intrastate comparisons.

Figure 5, the sample bill from NV Energy, depicts the cross-state comparative predicament. Those receiving service from NV Energy in southern Nevada pay for a broad array of charges that those

[bb] "Standard Offer Service (SOS) is electricity supply service sold by electric utility companies to a customer who does not choose an alternative electricity supplier." (https://www.psc.state.md.us/electricity/standard-offer-service/)

living in Connecticut do not; these include all the line items below “Electric Consumption,” with the exception of the “Basic Service Charge.”[103]

Figure 4A. Connecticut Standard Offer Service Sample Bill

Connecticut Standard Offer Service Sample Bill

Your Account Information

Customer Name Key: SMIT
GEORGE B SMITH
38 PALM TREE AVE
MILFORD, CT 06460

Account Number:	789-7897897-7897
Meter Number:	345345345
Trans and Dist Rate:	R-Residential
Generation Rate:	Standard Service
Billing Period:	10/14/10 - 11/11/10
Statement Date:	11/15/10
Next Meter Reading *(on or about)*:	*12/14/10*

Previous Charges & Credits

Amount of Previous Bill	10/15/10	$	82.93
Payment Received. Thanks!	11/04/10	$	82.93 cr
Balance Forward		$	**0.00**

New Charges & Credits
POD 1231231231231 (CYCLE 07)

Current Supplier: THE UNITED ILLUMINATING COMPANY
New Supplier: Supplier ABC, LLC

Generation Services Charge	341 kWh X $.115680	$	39.45
Total Generation Services Charges		$	**39.45**
Transmission per kwh	341 kWh X $.017465	$	5.96
Distribution Basic Service		$	15.85
Distribution per kwh	341 kWh X $.053234	$	18.15
Combined Public Benefits Charge	341 kWh X $.007375	$	2.51
Competitive Transition Assessment per kwh	341 kWh X $.015222	$	5.19
Non-Bypassable FMCC per kwh	341 kWh X $.001292-	$	0.44 cr
Decoupling Adjustment	341 kWh X $.000291	$	0.10
Pension Tracker and Earnings Sharing	341 kWh X $.000665-	$	0.23 cr
Total Delivery Charges		$	**47.09**
CTCleanEnergyOptions (100%)	341 kWh X $.013000	$	4.43
Total New Charges		$	**90.97**

Figure 4B. Connecticut Competitive Supplier Sample Bill

Connecticut Competitive Supplier Sample Bill

Total Charges for Electricity

Supplier (Any Energy Company)		
Generation Srvc Charge**	**700 kWh X 0.09990**	**$69.93**
Subtotal Supply Services		**$69.93**
Delivery		
Transmission Charge	**700 kWh X 0.02922**	**$20.45**
Distribution Customer Service Charge		**$19.25**
Distribution Charge per kWh	**700 kWh X 0.03467**	**$24.27**
Revenue Adj Mechanism	**700 kWh X 0.00079**	**$0.55**
CTA Charge per kWh	**700 kWh X 0.00116**	**$0.81**
FMCC Delivery Charge	**700 kWh X 0.00932**	**$6.52**
Comb Public Benefits Charge*	**700 kWh X 0.01275**	**$8.93**
Distribution Adj Charge***	**700 kWh X 0.00042**	**$0.29**
Subtotal Delivery Services		**$81.07**
Total Cost of Electricity		**$151.00**
Total Current Charges		**$151.00**

Figure 5. NV Energy Sample Bill

NV Energy Sample Bill

ELECTRIC - RESIDENTIAL SERVICE

Meter Number	Service Category	Service Period From	To	Bill Days	Meter Readings Previous	Current	Meter Multiplier	Billing Usage
ABC1234567	KWH	Nov 12	Dec 12	30	24039	25190	1	1,151

ELECTRIC CONSUMPTION 1	1,151.000	KWH	x	.11555	133.00
DEFERRED ENERGY ADJUSTMENT 2	1,151.000	KWH	x	.00000	0.00
TEMP. GREEN POWER FINANCING (TRED) 3	1,151.000	KWH	x	.00083	.96
RENEWABLE ENERGY PROGRAM (REPR) 4	1,151.000	KWH	x	.00132	1.52
ENERGY EFFICIENCY (EE) CHARGE 5	1,151.000	KWH	x	.00343	3.95
ENERGY EFFICIENCY AMORTIZATION 6	1,151.000	KWH	x	.00219 CR	2.52 CR
BASIC SERVICE CHARGE 7					10.00
LOCAL GOVERNMENT FEE 8				5%	7.35
UNIVERSAL ENERGY CHARGE 9	1,036.000	KWH	x	.00039	.45
TOTAL ELECTRIC SERVICE AMOUNT					**$154.71**

Thus, the EIA data is "picking up" a variety of costs and rate structures within states and across states that are unrelated to generation, transmission, and distribution.[cc] To evaluate the effectiveness of restructuring through the use of EIA data, these costs would need to be eliminated from their dataset to access the "true" price. Otherwise, we would be examining the effect of restructuring on pricing that carries with it a variety of embedded social and regulatory costs.[104]

[cc] A study of restructuring in Ohio concurs, finding that EIA data does not reflect large costs incurred by end-use customers, which accounts for more than 50 percent of the total bill in Ohio and perhaps other states, as well. It states: "...total bill information is not commonly provided in electric utility analyses. The typical data source for analyses of this sort is EIA data... which provides at best only the marginal rate that customers pay for their electricity (i.e., cents/kWh). However, in states with active utility commissions, such as Ohio, costs are borne by households and businesses through a long litany of additional riders and surcharges that itemize additional energy and energy-related costs on utility bills....These include everything from traditional charges for transmission and distribution (T&D), as well as additional cost pass-thrus for costs such as participating in competitive auctions, service reliability, deferred assets, etc. For example, in the American Electric Power (AEP) service territory (Columbus and Canton, Ohio metro areas in this study) there are approximately 20 additional riders on residential electric bills that amount to more than 50 percent of the total bill. These are costs that households face and that are not included in any competing analyses from EIA data. Moreover, utilities can pursue strategies to shift rents from the energy generation component of the consumer bill to other portions of the bill such as T&D or riders." See: Noah Dormady, Ph.D., Zhongnan Jiang, and Matthew Hoyt. "Do Markets Make Good Commissioners? A Quasi-Experimental Analysis of Retail Electric Restructuring in Ohio." John Glenn College of Public Affairs, The Ohio State University. February 11, 2017. Pages 9-10. Available: http://glenn.osu.edu/research/policy/policypapers-attributes/Do-Markets-Make-Good-Commissioners.pdf.

EIA's technical notes for *Electric Power Monthly* summarize the types of costs that can be included in electricity bills, with regard to Form EIA-861:

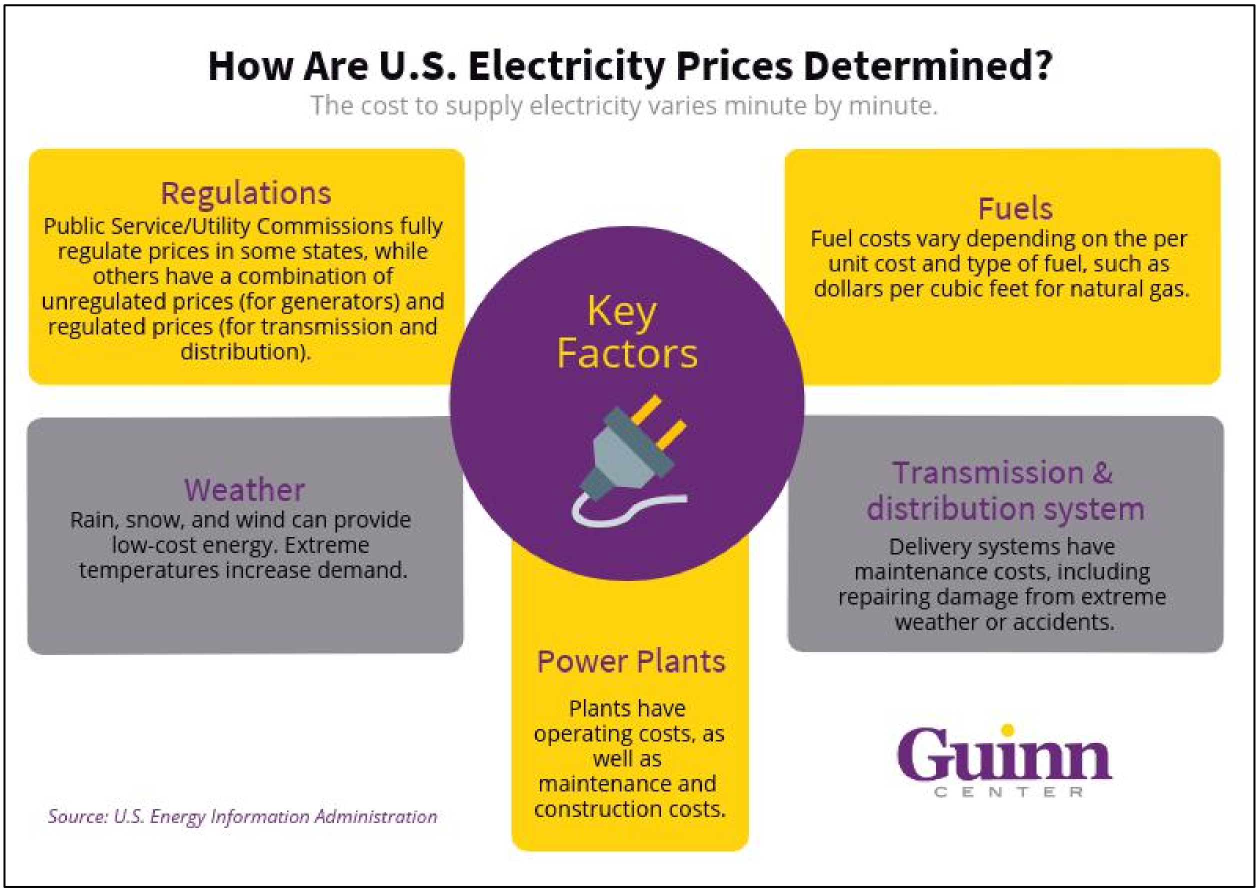
> The electric revenue used to calculate the average price of electricity to ultimate consumers is the operating revenue reported by the electric power industry participant. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric power industry participant operating revenues also include State and Federal income taxes and other taxes paid by the utility.
>
> The average price of electricity to ultimate consumers reported in this publication by sector represents a weighted average of consumer revenue and sales, and does not equal the per kWh rate charged by the electric power industry participant to the individual consumers. Electric utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs to the electric power industry participant for providing electrical service.[105]

The EIA technical notes, coupled with the Guinn Center's conversations with industry experts, reinforce the problematic nature of using the EIA data to make assertions about the effect of restructuring on electricity prices. Other issues further complicate use of the EIA data.

EIA explains that many factors influence electricity prices, as displayed in the infographic in Figure 6.[106] Those five key factors are: fuel costs; construction, maintenance, and operating costs of power plants; maintenance costs for the transmission and distribution system (i.e., the wires); weather conditions; and regulations (more broadly defined than the embedded social/regulatory costs discussed above to mean regulated prices under a vertically integrated utility and unregulated prices for generators/regulated prices for the wires in restructured states).[107] A FERC handbook specifies the impact of these factors on pricing in the context of supply and demand, stating that, "…key supply factors that affect prices include fuel prices, capital costs, transmission capacity and constraints and the operating characteristics of power plants. Sharp changes in demand, as well as extremely high levels of demand, affect prices as well, especially if less-efficient, more-expensive power plants must be turned on to serve load."[108]

Moreover, as an economic consulting firm notes, wages and taxes, along with the regulatory climate, can have an impact on electric rates.[109] In particular, "regulatory lag" can distort pricing: when costs rise, a vertically integrated utility must file for rate increases, which can take some time. But in restructured states, costs reflect market prices more immediately; this can understate rates for vertically integrated utilities.[110] What this suggests, perhaps, is an incongruity in the electric rate data if pricing in restructured states is reported as time($_{t}$), and pricing in traditionally regulated states is reported for time($_{t-1}$). This fundamental disparity in timing factors underscores yet another potential problem with use of the EIA data.

Figure 6. How Are U.S. Electricity Prices Determined?



Earlier, we cited a 2006 report that found that retail competition decreases price, with a price effect of about 5 to 10 percent. However, the author of that report recognized the bounds of price signal interpretation. He asserts, "…if the lower prices in retail competition states are due to competitive reforms they are a consequence of the negotiations over stranded cost recovery, regulated default service pricing, lower wholesale market and perhaps reforms in the regulation of distribution networks rather than retail competition per se."[111] In addition, he points to the near-constant changing of prices in the spot market, particularly the effect of hourly congestion problems, which is reflected in prices (e.g., as demand peaked during a hot summer day in 2005, there was import congestion into the Boston area, leading to a price that was 2.5 times that of Maine but lower than that of Connecticut, which typically confronts more import congestion than Boston).[112] To the extent that these sorts of factors inform pricing, it becomes ever more difficult to draw any conclusions about causal effects on rates. In the New England experience the author describes, all the states involved (Connecticut, Maine, and Massachusetts) have restructured markets, but the variation in prices is unrelated to restructuring.

Another researcher assessed twelve studies on electric market restructuring, some of which found positive effects on rates, while others found negative effects on rates. His approach was to evaluate the methodological robustness of these analyses, and he determined that all the conclusions were in doubt because of common problems, such as "…the failure to be precise about the reforms being evaluated, the use of a post-reform comparison price that is itself distorted, and an inadequate specification of causation."[113]

In sum, there are many factors that influence electric rates paid by consumers, and the EIA data, while excellent for the purposes intended—such as providing estimates of annual average retail prices of electricity, by year, state, and end-use sector—is not viable for examining the impact of restructuring on rate behavior. Electric rates and/or prices are not one-to-one corollaries of generation, transmission, and distribution costs but are indicators of the multiplicity of inputs that shape cost drivers. These can vary widely within states and across states, and because the EIA data is but a proxy for annual averages, an attempt to draw a conclusion regarding rate behavior in the context of restructuring versus the retention of a vertically integrated utility is likely to produce biased results.

B. Analytical Limitations

There are two additional points with regard to rates that we have yet to address. The first is the relationship between wholesale electric prices and rate behavior. The second is the effect of rate caps, rate freezes, and rate reductions on electric pricing. We will take each in turn, before proceeding to outcomes in states that have restructured their electricity markets. However, because the two often coincided, that sub-section will treat them in tandem, where applicable. The discussion here will help situate market mechanisms and regulatory choices in context and ascertain the extent to which their intersection has led occasionally to adverse outcomes.

i. Wholesale Electric Prices. All ratepayers—whether in markets with vertically integrated utilities or in retail electric choice markets—are vulnerable to changes in fuel costs and are exposed to market volatility. The process, and, accordingly, the pricing, differs with market structure, however. This sub-section suggests that there is heightened exposure under retail electric choice, as optimal market design implies a higher correlation between wholesale electric prices and retail rates. This can add to the consumer's benefit when wholesale electric prices are low but can confer a disadvantage when wholesale electric prices are high.

The official ECI (Yes on Question 3) comment to the Governor's Committee on Energy Choice (CEC) on the PUCN report in April 2018 disagrees with the idea that consumers are more exposed to market volatility under retail electric choice, asserting, "Nevadans are already exposed to 'market volatility' because NV Energy has persuaded the Commission [PUCN] to allow dollar-for-dollar recovery for fuel costs to force Nevada customers to protect the monopoly from market volatility. That means that rates already go up when natural gas is more expensive. Nevadans will be no less protected from market volatility than they are today."[114]

ECI (Yes on 3) cites a fact sheet from NV Energy, titled, *Understanding Your Bill: Bill Statement Charge Descriptions—Residential*. The fact sheet states, "The BTER [Base Tariff Energy Rate] reimburses the utility for fuel and purchased power costs the company pays on behalf of its customers. Increases or decreases are passed on dollar-for-dollar with no profit to the company. Utilities cannot, under Nevada law, profit from fuel and purchased power costs."[115]

As the fact sheet indicates, customers of vertically integrated utilities are not immune to pricing in the wholesale electric market.[dd, 116] After all, as discussed previously, utilities enter into bilateral contracts in both traditional wholesale markets and organized wholesale markets, particularly through PPAs. Specifically, NV Energy, through its participation in the western EIM, has access to the real-time market, which means that spot purchases, when necessary, can be very expensive.[ee] That said, in Nevada, under conditions of monopoly utility service, and pursuant to statute, the utility (NV Energy) cannot profit from fuel and purchased power costs (as noted above). Moreover, if the PUCN were to find that pass-through rates of wholesale costs were unduly burdensome, it could impose a regulatory remedy.[117]

However, in choice states, following restructuring, consumers are exposed more directly to wholesale electric costs, as the auction process becomes more deterministic in pricing. IPPs cannot remain in business if they cannot cover their costs, so when fuel costs rise, they submit higher bids into the market; the clearing price in an organized wholesale market reflects these costs.[118] IPPs also can take a profit under retail electric choice, so regardless of whether costs are low or high, they can mark up prices in service of profit maximization.[119]

Under the typical restructuring model, the state utility regulatory body (e.g., Public Utilities Commission, Public Service Commission, etc.) does not retain its authority over pricing, and the Federal Energy Regulatory Commission (FERC) does not have authority over sales at retail, as discussed in Section II. Specifically, under retail electric choice, the PUCN would no longer be able to able to intervene to protect consumers against higher rates, as that likely would abrogate the intent of the initiative petition, which requires that the Nevada Legislature establish "an open, competitive retail electric energy market."[ff, 120]

Turning to the research, one school of thought has characterized a "successful" restructured market as one in which electric rates approximate wholesale electricity costs more closely. A study on restructuring in Texas states that, "…residential rates in competitive areas are highly reflective of wholesale rates, which suggests that electricity providers are minimizing costs in meeting market demands. By contrast, residential rates in non-competitive areas do not generally reflect wholesale rates. Furthermore, we find a shrinking gap between residential rates and wholesale rates in

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[dd] For example, in New England, in the first half of 2014, EIA found that residential customers of both full-service utilities and restructured suppliers experienced similar rate increases of about 11.8 percent, with the primary driver being the "sharp rise in wholesale power prices." See: U.S. Department of Energy, U.S. Energy Information Administration. "Residential Electricity Prices Are Rising." September 2, 2014. Available: https://www.eia.gov/todayinenergy/detail.php?id=17791.

[ee] On real-time pricing, see: ISO New England. "FAQs: Day-Ahead Energy Market—Commitment, Scheduling, and Dispatch." Available: https://www.iso-ne.com/participate/support/faq/da-market-commitment.

[ff] Customers who retain default service may receive rates that are regulated by the PUCN, as was the case when states initially restructured (see, for example: Kevin E. McCarthy, Principal Analyst. "Electric Restructuring in Other States." Connecticut Office of Legislative Research. OLR Research Report: 2002-R-0994. December 20, 2002. Available: https://www.cga.ct.gov/2002/olrdata/et/rpt/2002-R-0994.htm). But that decision will be determined ultimately by the Nevada Legislature.

competitive areas, which is consistent with improvements in firm and market efficiency. This also has not generally been the case in non-competitive areas."[gg, 121]

While there is no consensus as to the effects of restructuring on rate behavior, most researchers agree that wholesale electric costs contribute substantially end-user prices. As one report observes, exogenous factors, including natural gas fluctuations and generation technology advances, have driven electricity rate changes more than the effects of restructuring itself. It asserts, "As natural gas prices nearly tripled during the first half of the 2000s, the impact on retail rates and the rents created for infra-marginal generation were far greater than they would have been under regulation. During 2006 and 2008 the U.S. natural gas price peaked above $11/MMBTU. The higher gas prices drove up generation costs and power market prices."[122]

Another study reports the following: "In particular, retail price in states with retail markets saw a much steeper climb from 2003 to 2008, followed by a price decline in some retail states (especially Texas and New Jersey) for several years until recently, which coincides with the gas price movements in the past two decades."[123] This study points to the inability to disentangle retail electric choice from other factors, including, amongst others, wholesale costs: "The real price impact of retail electricity choice is difficult to measure because of, among other things, rate variations with respect to wholesale price, the customer's load profile, on- and off-peak conditions, marketing costs, and contract duration…Implementing retail electricity choice does impose some new costs. These include new billing procedures and metering that are compatible with the retail service offerings."[124]

Natural gas is the most salient fuel source in this discussion as many have noted, given that the "…pricing of electricity nationally has become closely aligned with the cost of natural gas, which is the principal source of fuel for peak generation."[125] In addition, natural gas sets prices "during the most profitable hours in the energy market"; "…annual average electricity prices in PJM, ISO-NE, and NYISO clearly mirror the price of gas."[126]

Even a small share of exposure to natural gas can have an impact: "…restructuring of generation greatly increased the exposure of electricity rates to natural gas costs, even if a fairly small share of electricity was sourced from gas-fired plants."[127] One analysis emphasizes the relationship between generation fuel mix and electricity rates, noting not just how closely these factors are intertwined but pointing to the complexity of the relationship:

> Differences in generation fuel mix have a large impact on electricity rates in different states. Some states are more exposed to increases in natural gas and oil prices because of their greater reliance on such fuels to generate power. Not only were such states more likely to pursue restructuring in the first place, they have continued to be relatively exposed to recent sharp increases in fuel prices. In contrast, many "regulated" states have relatively large portions of their generation supply coming from coal, nuclear, and hydro; and electricity prices have consequently been somewhat shielded from fuel price increases (although coal and uranium prices have also risen significantly in recent years). Any comparison of state electricity rates that does not account for the relative impact of generation fuel mix will produce misleading results.

[gg] Recall that Texas has both restructured and non-restructured areas.

> Thus, comparing "restructured" Massachusetts, where 50% of electric supply is generated from natural gas and the average retail rate is about 17¢/ kWh, to "unrestructured" Idaho, where 80% of supply is from hydroelectric plants and the average retail rate is 6¢/kWh, says nothing about the relative benefits or deficiencies of the "regulated" or "unregulated" paradigms. At most, all this indicates is that fully depreciated hydroelectric dams provide cheap electricity. Electricity rates in Idaho and Massachusetts will differ dramatically over time, but the differences will be completely unrelated to restructuring.[128]

Therefore, it is impossible to isolate the effects of restructuring on electricity rates. We have already documented such confounding factors as weather variations, timing, congestion issues, and more, but perhaps nothing is more intertwined with retail electric choice than wholesale costs, specifically, natural gas. The preceding discussion should not be misconstrued to suggest that electric prices in restructured states will increase necessarily because of natural gas's pronounced contribution to costs. On the contrary, natural gas prices have been volatile, historically; when they are low, consumers in restructured states—by virtue of their increased exposure to the wholesale market—realize benefits from lower fuel costs.[129] But when they rise, consumers may pay higher electricity bills as a result of pass-through from IPPs to competitive suppliers.[130]

Figure 7 displays the national annual average natural gas spot price in current dollars and inflation-adjusted dollars for 1997-2017.[131]

Figure 7. Annual Natural Gas Spot Price (Dollars per Million Btu)

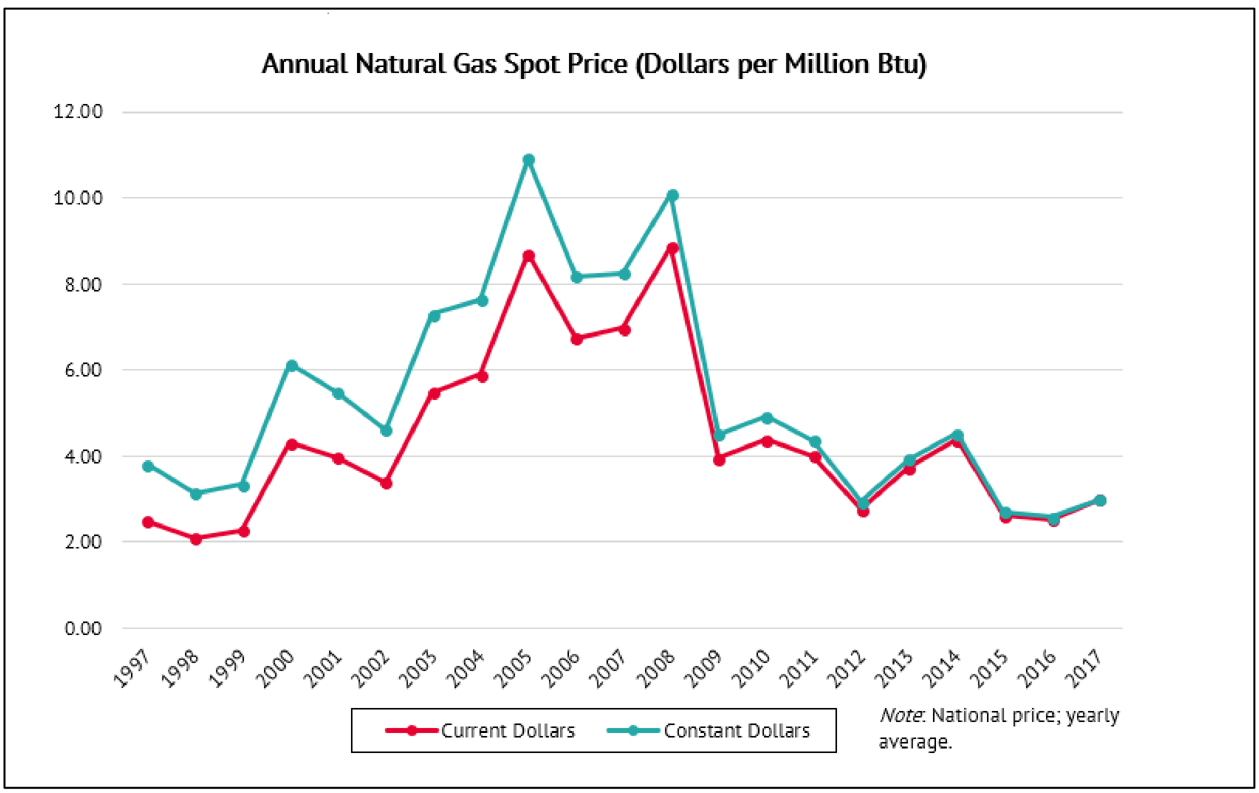

Figure 7 shows that natural gas prices tend to exhibit some fluctuations. In inflation-adjusted dollars, the annual average natural gas spot price is about the same as it was in 1997, which is quite low. In fact, EIA has forecasted that natural gas production will set a record in 2018.[132] And "[w]hen natural gas is abundant and cheap, utility bills are lower in most areas, with the notable exception right now of the New England area, where politically-motivated pipeline constraints have led the absurd outcome of residents of the states north of New York paying much higher prices than the rest of the country, and having to actually import LNG [liquefied natural gas] from Russia in order to meet the region's natural gas demand."[133] The expectation is that natural gas prices will continue to remain low.[134]

Given that natural gas prices exert such strong influence over end-user electricity rates, the pricing trend suggests that consumers could realize benefits from a restructured market, as wholesale prices and retail rates are more closely connected than they are under a vertically integrated utility. However, the data is not predictive, and we cannot anticipate exogenous shocks. As Figure 7 indicates, spikes in 2005 and 2008 reflect wholesale market volatility. For example, no one could have expected that Hurricanes Katrina and Rita would have disrupted offshore supply or caused such significant damage to major pipeline segments so as to cause "an extreme escalation of prices."[hh, 135] In the forthcoming "State-Specific Outcomes" sub-section, a good portion of the discussion will center on the effects of changes in wholesale natural gas prices on electricity rates in various states.

In 2015, the most recent year for which data is available, 48.1 percent of Nevada's primary energy consumption came from natural gas.[ii, 136] By way of contrast, in the inset quote above (page 37), the authors pointed to the difference between Massachusetts' natural gas exposure and Idaho's exposure, and, accordingly, the relative influences on electric rates. That report was published in 2008, so we pulled the rough consumption estimates for each of those states for that year. For Massachusetts, natural gas as a percentage of total consumption was 28.9 percent; for Idaho, it was 16.8 percent.[137] The 12.1 percentage-point difference in consumption may have helped translate into a price differential of 11¢/kWh (that is, setting aside other electricity rate influences). This lends support to the assertion that even incremental exposure to natural gas can be deterministic in rate setting.

[hh] It is not clear what happened in 2008, as the industry was oversupplied, but natural gas prices may have been mapping to oil and global liquefied natural gas, which were relatively high and factored into price setting. See: Richard G. Smead, Director, Navigant Consulting, Inc. 2010. "Price Instability in the U.S. Natural Gas Industry: Historical Perspective and Overview." Prepared for The Task Force on Natural Gas Market Stability. Available: http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/Introduction_to_North_American_Natural_Gas_Markets_0.pdf.

[ii] Ideally, we would obtain data on Nevada's actual exposure to natural gas in the electric generation fuel mix, but consumption estimates are but a rough approximation. (Generation data is available, but generation and consumption are not the same. Once electricity is generated onto the grid, its fuel type cannot be differentiated. Source: Guinn Center conversation with EIA.) EIA provides data on consumption, but it should be interpreted with caution, not only because of the differentiation problem but also due to the fact that it reflects consumption across all sectors and is not intended to represent the share of natural gas in the electric generation fuel mix.

ii. Rate Caps, Rate Freezes, and Rate Reductions. With the exception of Maine, all states that pursued restructuring (retail choice) implemented some form of rate caps, rate freezes, and/or rate reductions.[jj, 138] They were designed to protect consumers through the transition process to a fully competitive market.[139] The general idea was that consumers might face unexpected rate increases in the initial phase of restructuring, so rate caps, freezes, and/or reductions could smooth the transition.[140] A separate consideration turns on stranded assets: if there are stranded costs by virtue of divestiture, and the Nevada Legislature decides that the utility must be compensated by passing on those costs to ratepayers, caps can ease that burden.[141]

Here is an example of a rate cap from Pennsylvania:

> There are statutory caps on electric distribution utility rates: rates for standard offer service (i.e., service for customers who do not choose a generation supplier) and non-generation service are capped at January 1, 1997 levels until July 1, 2001; rates for generation, including transition charges, are capped at January 1, 1997 levels until January 1, 2006. In some distribution utility service areas, generation caps are in place until 2008-2011. Many distribution utilities have also extended distribution rate caps until 2003-2005. Pennsylvania did not require rate reductions, although several distribution utilities agreed to reduce rates in the first year of retail choice. These reductions were to be lowered and phased out over a two to three year period.[142]

Another example is California, which, prior to repeal, instituted a 10 percent rate reduction so that its utilities could recover stranded costs.[143] Reducing rates allows utilities to recover stranded costs

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[jj] With the exception of two jurisdictions, rate caps, rate freezes, and rate reductions were established through enabling legislation. (An example is Pennsylvania; see: P.L.802, No.138, the "Electricity Generation Customer Choice and Competition Act of 1996," available at: Pennsylvania General Assembly. 1996. "House Bill 1509: The Electricity Generation Customer Choice and Competition Act." Available: http://www.legis.state.pa.us/cfdocs/legis/li/uconsCheck.cfm?yr=1996&sessInd=0&act=138.) The District of Columbia's enabling legislation delegated authority to the District of Columbia Public Service Commission ("the Commission") to set alternative forms of regulation. The legislation prescribes that the Commission "...may adopt an alternative form of regulation...if the Commission finds, after notice and a hearing, that the alternative form of regulation: (A) Protects consumers; (B) Ensures the quality, availability, and reliability of regulated electric services; and (C) Is in the interest of the public, including shareholders of the electric company. Alternative forms of regulation may include: (A) Price regulation, including price freezes or caps;...[.]" (*Source*: Council of the District of Columbia. 2000. "Retail Electric Competition and Consumer Protection Act of 1999." Page 18. Available: https://code.dccouncil.us/dc/council/laws/docs/13-107.pdf.) "Order No. 11576, issued December 30, 1999... authorized a 7 percent reduction in PEPCO's rates for residential customers and a 6.5 percent reduction in rates for commercial customers, to be implemented in three phases." (*Source*: Public Service Commission of the District of Columbia. n.d. "Electric Restructuring — Formal Case No. 945 and Subsequent Cases." Page 3 of 38. Available: https://dcpsc.org/PSCDC/media/PDFFiles/Electric/ElectricRestructuring.pdf.) The New York Public Service Commission (PSC) administered rate reductions independently of the New York State Legislature (see: Sheldon Silver, Michael J. Bragman, and Paul D. Tonko, Chair. 1999. "Shedding Light On The Governor's Failed Electric Utility Restructuring: A Briefing Paper on Moving to Competition in the Electric Industry." New York State Assembly. Available: http://www.assembly.state.ny.us/Reports/Energy/199902/). However, also note that New York restructured its electric power industry through a PSC opinion and order (see: Channele Carner. 2003. "Status of State Electric Industry Restructuring Activity — as of February 2003 —." U.S. Department of Energy, U.S. Energy Information Administration. Available: http://large.stanford.edu/publications/coal/references/docs/restructure.pdf.)

by establishing a lower price for electricity while receiving compensation for its losses, often through a surcharge on its wires service; if rates were not capped, frozen, or reduced, stranded costs could impose an undue burden on the consumer, as these costs would be assessed on top of "normal" electricity rates.[144]

While consumer groups largely favor rate caps, freezes, and/or reductions, critics find them problematic, contending that they do not permit consumers to realize actual market prices, or at least prices closer to the wholesale price of electricity.[145] As Ned Ross (Direct Energy), who leads the Retail Energy Supply Association (RESA) state and federal advocacy efforts as a 2018 Electric Caucus Chair for Nevada, explained to the PUCN, "Price caps do not achieve price stability in a competitive market. They can destabilize the market, as they did in California. So what we have to do is set the market up properly so that competition is invited, and that alone will be the…best preventative measure from having high prices."[146]

Furthermore, many states that established capped rates found that they discouraged market entry by competitive suppliers, as the caps were often below market rates, creating a disincentive to competition.[147] As one report notes, "…none of the retail electricity market designs yield instant price reductions for customers. States that held prices artificially low during the transition to a competitive market may have seen lower prices initially; however, the long-run effect of artificially depressed prices is a misallocation of resources and an inefficient electricity market. Consumers have no incentive to switch to an alternative electricity provider and providers have no incentive to enter the market to serve residential customers."[148]

In its restructuring enabling legislation (Senate Bill 7), Texas established a unique model to smooth transition, called the "Price to Beat."[149] Several industry experts told the Guinn Center that if Question 3 were to pass, and some form of rate caps were deemed necessary, the Texas model would be the one to emulate.[150] "Texas required that electricity providers affiliated with the incumbent utility charge a 'price to beat' until the incumbent lost sufficient market share to alternative providers. This price was designed as a price floor and ceiling. In other words, it was designed to prevent the incumbent from offering artificially low rates to stifle competition and undercut new market players. It was also intended to provide a cap, or ceiling, so that customers that didn't switch providers still received some benefit."[kk, 151]

For the purposes of this report, rate caps, freezes, and reductions are relevant for two reasons: (1) most of the macro-level research that showed a link between restructuring and decreased electric rates was published prior to the expiration of rate caps, and to the extent that prices were found to be lower in restructured areas, these results may be skewed by the depressive effects of rate caps, freezes, and reductions—they are inherently time bound; and (2) many of the state-specific outcomes that we will discuss in the next sub-section were driven by simultaneous expirations in rate caps, freezes, and reductions—when prices became aligned more closely with wholesale costs—and

[kk] The incumbent utility can be understood as the preexisting vertically integrated utility with exclusive franchise over service in a designated territory.

volatility in those very same wholesale electric costs in electricity markets, which, depending on the timing, either exacerbated the problem or helped mitigate it.[ll]

State-Specific Outcomes: Wholesale Electric Prices and Rate Caps/Freezes/Reductions

In this sub-section, we document the experiences of several states that restructured their electricity market ("choice states"), with particular regard to rate behavior, typically in the context of expiring rate caps and changes in wholesale electric costs.[mm] We also address macro-level losses in consumer savings.

A report prepared for the Maryland Public Service Commission stated the following:

> After deregulation had been in place for three to five years, states' rate freezes ended and, predictably, rates spiked dramatically to reflect current wholesale market prices....Some states laddered in rate increases, but residential customers still experienced rate hikes of over 50% after states lifted the freeze. Some states experienced rate increases up to 100%. Deregulation alone did not cause these rate increases, but it did exacerbate the uncertainty and instability that followed natural gas supply disruptions and electricity shortages in some transmission constrained areas. Multi-year price freezes coupled with market forces that drove prices up combined to produce significant rate shocks in many jurisdictions. Although all states have experienced increases in electric rates, the gap between average rates in restructured and regulated states has widened, with average rates in restructured states increasing more dramatically.[152]

In Maryland, upon expiration of its rate freezes, residential rates for the 2005-2006 procurement period increased in the range of 35 percent to 72 percent, with additional factors such as heightened demand and rises in natural gas prices in the wake of Hurricanes Rita and Katrina.[153] In the previous year, the expectation that Maryland's customers of Baltimore Gas & Electric would face a 72 percent rate increase was recorded in a docket before the Pennsylvania Public Utility Commission; these customers evidently had remained with the incumbent utility, which had to compete in the open market for power after divestiture.[154] (Maryland's legislature ultimately deferred a substantial portion of the increase.)[155]

Neighboring state Delaware experienced a similar shock in 2014, though it was on the competitive supply side. Given that that was considered a particularly cold winter, both customers with Delmarva, the incumbent utility, and those using a competitive supplier experienced increases in their

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[ll] "The time period examined, however, makes an enormous difference as rates in restructured states increased at a pace nearly 50% higher than those in non-restructured states between 1997 and 2007 but have actually declined slightly since 2007. Average rates in states that did not restructure have continued to increase since 2007, though at a slightly lower pace than between 1998-2007. Overall there is almost no difference in the change in average rates for the two groups over the full sample from 1998-2012." (*Source*: Severin Borenstein and James Bushnell. 2015. "The U.S. Electricity Industry after 20 Years of Restructuring." Energy Institute at Haas, University of California, Berkeley. Page 16. Available: https://ei.haas.berkeley.edu/research/papers/WP252.pdf.)

[mm] Some of these reports rely on EIA data, and in others, the data source is unclear. Given the limitations therein, the reader is advised to interpret the state-specific outcomes with caution.

electricity bills.[nn, 156] However, customers who procured electricity through a retail supplier "…have seen their per-kilowatt-hour rate mirror spot electricity market rates, which have increased more than 400 percent in the past two months, according to information released by PJM Interconnection, the regional grid manager."[157]

In anticipation of expiring rate caps, the Pennsylvania Public Utility Commission issued a report showing that Allegheny Power's residential customers could expect a 4 percent increase for residential customers and that PPL's residential customers might experience as 30.4 percent increase once the caps were lifted.[158] That regulatory body also released a fact sheet that indicated that: (1) customers should expect to see an increase in their bills upon expiration of caps, as the market price for electricity had risen; and (2) elimination of the caps would mean that Pennsylvanians could choose a competitive supplier that may offer a better price for generation (at the time, the competitive supply rate was "as much as 4 cents per kWh cheaper than the default service price offered by the utility").[159]

New Jersey experienced rate turbulence with the expiration of rate caps at the end of its transition period in 2003.[160] Historically, the state's electric prices had been some of the highest in the nation, so the purpose of its restructuring legislation was to lower costs.[161] And, in the short term, New Jersey's residents enjoyed lower rates for electricity.[162] Once the transition period ended, rates began to increase again, from 9.3 cents/kWh in 2002 to 14.3 cents/kWh in 2011, which represents a 53.8 percent increase.[163] Rates increased by 19 percent in the immediate aftermath of the expired caps.[164] Given that New Jersey's electricity prices are associated significantly with natural gas prices, however, recent pricing trends in the wholesale market (i.e., lower costs for natural gas) have provided some relief, though the state's electricity prices have remained consistently above the national average price.[165]

The New England states, when taken together, exhibited similar properties as other states that have restructured (i.e., adopted retail energy choice), though the states in question—Connecticut, Massachusetts, New Hampshire, and Rhode Island—tended to use rate reductions and freezes rather than caps.[oo, 166] Through the transition period, the regional average electric rate for small consumers decreased or stayed flat. At the end of the transition period, rates have tended to climb, with the occasional dip.[167] This was attributed to several factors, including the underlying price of natural gas and regional supply constraints: "Natural gas prices gradually increased over much of that period, and as the proportion of gas-fired generation in New England grows relative to power derived from other fuel, the relationship between the underlying price of the natural gas commodity and the

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[nn] For example, one individual who switched from the Standard Offer Service provided by the incumbent utility, Delmarva Power, received a $950 supply charge; this amount was three times that of the previous month, though the family had consumed less electricity. (*Source*: Aaron Nathans. "Electric Customers Feel Winter's Costly Impact." *News Journal*. March 3, 2014. Available: https://www.delawareonline.com/story/money/2014/03/02/electric-customers-feel-winters-costly-impact/5955275/.)

[oo] Vermont did not restructure its electricity market, and Maine did not impose a rate cap, freeze, or reduction. (*Source*: Reishus Consulting, LLC. "Electric Restructuring in New England – A Look Back." Prepared for New England States Committee on Electricity (NESCOE). December 21, 2015. Available: http://nescoe.com/resource-center/restructuring-dec2015/.)

resulting electricity supply price continues to strengthen....annual prices have been higher...in New England because of regional supply constraints that caused certain winter months to spike, pushing up the region's rolling average price in the last few years."[168]

In the Midwest, all states that restructured encountered issues tied to wholesale electric prices, expiring rate caps, or both. Michigan's retail electric structure has been described as "unique."[169] In a state-commissioned survey of 26 questions regarding electric choice published in 2013, a joint response from Consumers Energy, DTE Energy, and MEGA (e.g., incumbent utilities) stated: "For most of the state, generation and distribution assets are owned by utilities and fully regulated by the MPSC [Michigan Public Service Commission], transmission assets are owned by stand-alone companies, and a limited portion of customers (10% of load) are able to obtain generation from alternative energy suppliers (AESs)."[pp, 170]

However, no residential customers currently have access to retail choice, which is the result of a 2008 law that requires that "no more than 10 percent of an electric utility's average weather-adjusted retail sales for the preceding calendar year may take service from an alternative electric supplier at any time.[171] The Michigan experience speaks to the vicious circle that can arise if the market is not restructured properly, as emblematized by rate caps, reductions, and management of stranded assets: in the short term, a rate reduction and price cap held prices low at the same time as energy costs were increasing.[172] However, no electric choice structure developed, as retail suppliers could not compete with the regulated rates, which left ratepayers with no take-up option for choice.[173] The expiration of the rate caps resulted in increased electricity rates: residential customers of Edison [MEGA] were faced with a 12.5 percent increase in rates upon expiration of the cap, and residential customers of Consumers Energy, an incumbent utility, received a combined 9.8 increase in rates at the same time.[174] In addition, while both customers of the incumbent utilities and those who selected a competitive supplier initially were required to pay for stranded costs, later regulatory decisions incentivized switching by levying the costs only on those who remained with the utility.[175] Given that no retail electric market developed, consumers effectively subsidized restructuring that was nonexistent in practice.

[pp] For the report on the 26 electric choice questions, see: Michigan Public Service Commission, Department of Licensing and Regulatory Affairs, and Michigan Energy Office. "Readying Michigan to Make Good Energy Decisions: Electric Choice." November 20, 2013. Available: https://www.michigan.gov/documents/energy/electricc_report_440539_7.pdf.

A quasi-experimental analysis conducted on restructuring in Ohio found that residential customers did not experience rate decreases with the transition to a market-based model.[qq, 176] The study found the following: "For most of Ohio's residential retail load, prices have not declined since retail restructuring. For four of the seven metro areas in our study, retail restructuring resulted in higher month-to-month price trends than the trend that existed before restructuring. And while the other three territories of Cincinnati, Columbus and Dayton have seen month-to-month price trends decline or not change relative to pre-restructuring, households in those territories paid a higher real (inflation-adjusted) price, on average, in the period following restructuring than they did in the period preceding."[177] Note that Ohio froze electric rates from 2001 through 2005.[178] And while the EIA data does not reflect fully all the contributing factors to retail electricity rates, it does provide a rough approximation of the trend once the freeze was lifted: all sectors experienced relatively flat electricity prices prior to restructuring and through the freeze, after which prices began to climb, perhaps most steeply for residential ratepayers.[179]

The Illinois' Citizens Utility Board expected the state's consumers to see rate increases of 40 percent to 60 percent when its caps were eliminated.[180] The caps expired in 2007, leading to "rate shock" and soaring/surging prices, with customers experiencing double- and triple-digit increases in their electric bills in 2007.[181] Residential customers of ComEd (a utility) witnessed a 26 to 56 percent increase in their bill between 2006 and 2007; large commercial and industrial customers saw their bills increase by 60 percent to 70 percent, though some large customers had increases of more than 100 percent.[182] At Ameren, another utility, those increases were 49 percent to 125 percent for residential customers and 80 percent to 130 percent for large commercial and industrial customers.[183] The Illinois State Attorney General alleged that customers would pay an extra $4.3 billion between 2007 and 2009 "because of manipulation of prices by wholesale suppliers (including affiliates of ComEd and Ameren) in the electricity auction used to set the utility rates under deregulation. The state's complaint alleged that the deregulated generation affiliate of ComEd was charging the utility three times its actual cost to generate electricity to serve the utility's customers."[184] Eventually, the state brokered a deal to offer rate relief in the amount of $1 billion to consumers, and rates decreased with surplus capacity in wholesale markets and low commodity prices.[185]

[qq] There is one potential limitation to this analysis, which is that the authors used a monthly publication of utility rates issued by the Public Utilities Commission of Ohio for the years 2004 through 2015, but this data captures the full bill with only Standard Offer Service and does not include bills for those who selected a retail supplier. While they acknowledge this potential problem, the authors assert that: (1) the generation portion is less than 50 percent of the total bill in Ohio, so consumers incur the same fees, regardless of generation supplier; and (2) competitive standards established in this time frame ensured that Standard Offer Service for generation better reflected market rates, which means that Standard Offer Service and retail supply service rates approximated one another closely. (*Source*: Noah Dormady, Ph.D., Zhongnan Jiang, and Matthew Hoyt. "Do Markets Make Good Commissioners? A Quasi-Experimental Analysis of Retail Electric Restructuring in Ohio." John Glenn College of Public Affairs, The Ohio State University. February 11, 2017. Available: http://glenn.osu.edu/research/policy/policypapers-attributes/Do-Markets-Make-Good-Commissioners.pdf.)

Before moving westward with our examination of two additional states, Montana and Texas, it is important to note here that the problem is not necessarily with restructuring as a concept. The challenges, uncertainty, and volatility in rate behavior stem directly from market design. In some instances (e.g., Michigan), competition in electric energy suppliers did not thrive because there was no mechanism for retail suppliers to compete with the incumbent utility providing Standard Offer Service. Or, alternatively, as with Illinois, customers of the incumbent utility were penalized for not switching through an institutional scheme that helped facilitate market manipulation. In both cases, relational aspects became salient. Specifically, how the states implemented restructuring mattered for the variations in pricing offered by the incumbent utility versus retail suppliers. It is this relationship that can come to define the "success" or "failure" of restructuring. As we shall discuss shortly, Texas devised a solution to the problem, though that state has not been without its share of restructuring-related difficulties.

Moreover, while supporters of retail choice in Nevada and elsewhere emphasize the benefits it provides to consumers, our analysis indicates, somewhat ironically, that residential customers, in particular, have tended to remain with the incumbent utility. The reasons for the lack of residential customer switching are many:

1) With the exception of Texas, which has required customers in restructured areas to select a retail supplier upon expiration of the "Price to Beat" cap/floor, all states that have transitioned to a competitive retail market have permitted its ratepayers to remain with the incumbent utility; and

2) the above means that some consumers either are unaware that they can switch; did not switch because of familiarity with incumbent utility; did not switch because of better rates at the incumbent utility (i.e., in those states where competition has been impeded); have switched but ultimately decided to return to the incumbent utility; or could not switch due to a lack of creditworthiness, which translated into competitive suppliers being unwilling to "do business" with these individuals and the incumbent utility, in turn, charging higher prices to offset potential losses that may result from taking on non-creditworthy customers.[rr, 186]

Figure 8A replicates a graph from a study on retail electric choice that depicts the percentage of eligible residential customers that have switched to a competitive supplier; as the authors note, it does not capture megawatt hour sales.[187] Excluding Texas, due to its mandate that ratepayers switch, approximately one-third of all eligible residential customers have switched to competitive suppliers.[188] "Overall, 16% of the total electrical energy sold in the U.S. in 2014 was sold by competitive retail energy suppliers."[189]

[rr] "[Texas] requires retail choice program participation by all customers served by investor-owned utilities in the footprint of the Electric Reliability Council of Texas." *Source*: Mathew J. Morey and Laurence D. Kirsch (Christensen Associates Energy Consulting LLC). 2016. "Retail Choice in Electricity: What Have We Learned in 20 Years?" Prepared for Electric Markets Research Foundation. Page 4. Available: https://sites.hks.harvard.edu/hepg/Papers/2016/Retail Choice in Electricity for EMRF Final.pdf.

Figure 8B presents a replication from the same study but for commercial and industrial (C&I) loads.[190] It is not directly comparable to Figure 8A, as that computed data on percentage of eligible customers, while Figure 8B computes the percent of loads. Regardless, each provides an approximation of the rates of competitive electric service take-up, by state. A comparison of Figure 8A and 8B indicates that C&I customers tend to adopt retail electric choice at higher rates than their residential counterparts. For example, in Illinois, where the gap is narrowest, the C&I switching rate is about 77 percent, while residential take-up is about 60 percent; the widest gap is in the District of Columbia, with a C&I switching rate of around 62 percent and residential take-up of approximately 14 percent. As the study notes, the benefits for C&I customers outweigh the costs, but the equation is reversed for residential customers.[191] This report addresses more specific reasons for the discrepancy in Section IV, with respect to consumer impact.

Figure 8A. Residential Customers Taking Competitive Electric as Shares of Eligible Customers, 2014

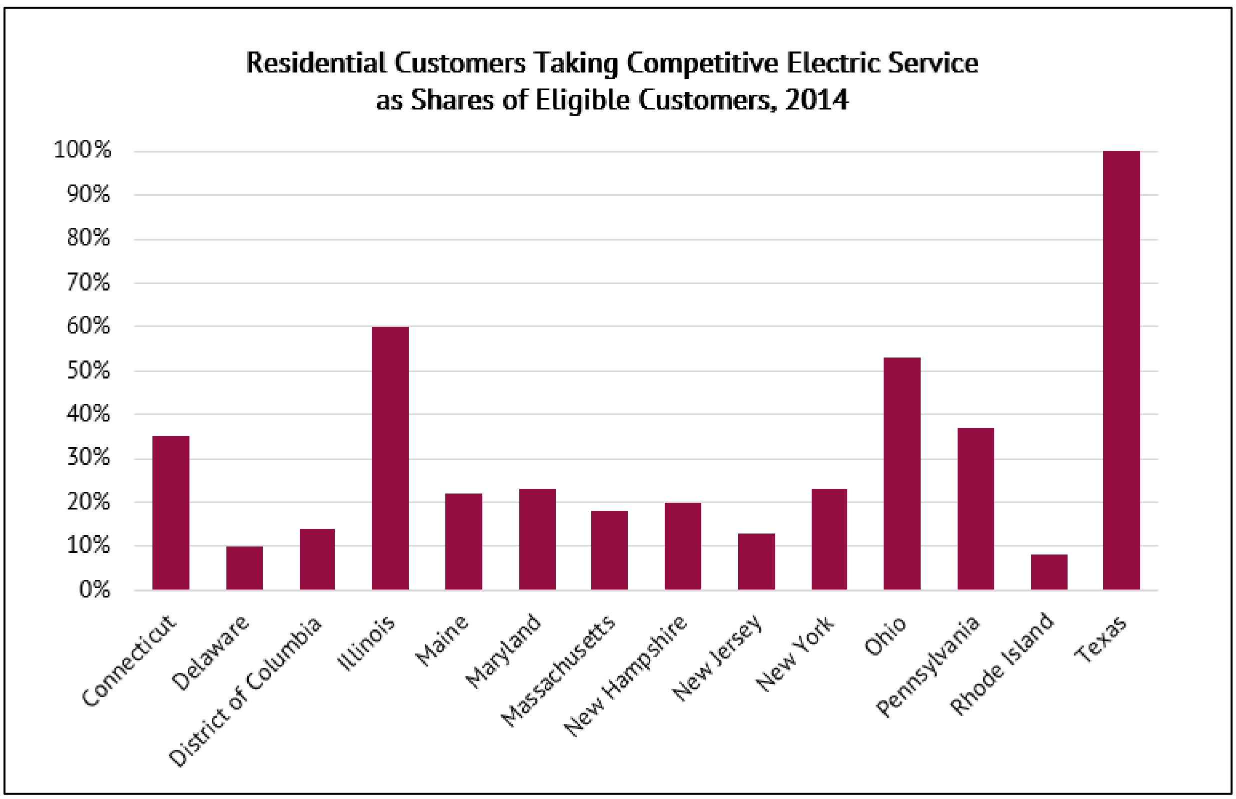
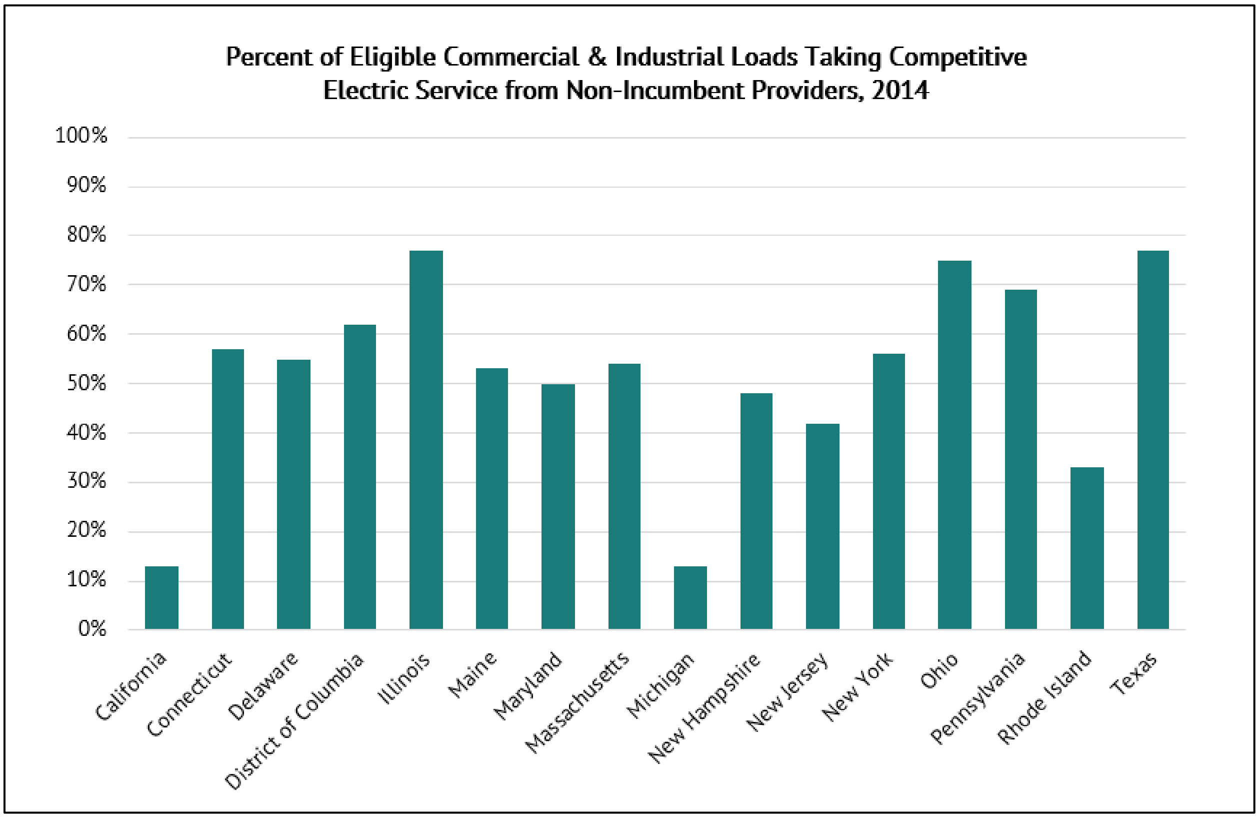


Figure 8B. Percent of Eligible Commercial & Industrial Loads Taking Competitive Electric Service from Non-Incumbent Providers, 2014



Returning to state-specific outcomes, Montana is the cautionary tale of restructuring. Assets were sold for $2.7 billion, with large fees assessed by Goldman Sachs.[192] The utility sold its generation assets to a company that eventually filed for bankruptcy protection, contributing to "skyrocketing electricity rates."[193] The state had instituted rate caps for an initial two years and an additional two years for those who did not have access to retail choice at the end of the transition period.[194] The first rate caps expired in 2000, right as California began to experience its energy crisis, which caused wholesale prices to increase throughout many western states, including Montana.[195] The final set of rate caps expired in 2002, and rates increased.[196] At first, large customers bore the brunt of wholesale market exposure, particularly in 2001, but the combination of expiring caps and wholesale price increases resulted in "significant cost increases for…electricity" across all ratepayer types.[197] The state repealed retail electric choice in 2007 for all but those with loads of five or more megawatts.[198]

Texas, unlike Montana, is considered by supporters of retail electric choice as the gold standard for restructuring. Its use of the "Price to Beat" model, which allowed retail suppliers to compete with incumbent utilities during the initial phase of the process, helped smooth the transition. And currently, as noted previously, Texans must choose a competitive supplier; there is no option for Standard Offer Service (SOS), which means that incumbent utilities and retail suppliers are not in a push-pull for consumers. In fact, residents in restructured areas do not have a default option unless their retail supplier cannot continue service, in which case the Public Utility Commission of Texas supplies these customers with a temporary "safety net" through a Commission-designated provider.[199] With respect to the generation component of electricity delivery, retail suppliers compete on their own merits with a variety of product offerings and prices. Utilities continue to provide the wires service.

One report on restructuring in Texas found that, while residential customers in competitive areas paid higher average prices for electricity than those in non-competitive areas, for the period January 2002 through December 2016, residential prices declined in competitive areas and increased in non-competitive areas over the same time frame.[200] However, a competing report observes that restructuring has led to higher prices and more volatility in competitive areas of the state, relative to non-competitive areas.[201] It states, "…prices in the deregulated areas steadily climbed as natural gas prices rose in the mid-2000s. From 2002 to 2006, the price to beat rose 88% and the competitive offers rose 62%. In contrast, rates in regulated areas of Texas rose only 24% during this period. For over a decade, deregulated areas of Texas have consistently paid more for electricity than regulated areas of the state. And prices are more volatile in deregulated areas."[202] The report points to another troubling problem in Texas, which is the issue around stranded costs:

> Estimates of stranded costs were calculated at various points during the transition to deregulation in order to provide for early mitigation and recovery, as applicable. Due to fluctuating market conditions over time and regulatory decisions, estimates of stranded costs ranged from negative $2 billion (during periods of high natural gas prices making higher-cost plants more economical) to more than $6.5 billion. By the time the issue was fully litigated, the total amount customers will pay amounted to more than **$9.5 billion**. Even though customers are on the hook for this amount, private equity investors resold the assets at a significant profit under better market conditions. While the state's policy was well-intended, it did not adequately anticipate the rapidly changing market conditions. This experience has been costly for businesses and residents of Texas, and underscores the complexities and trade-offs of deregulation.[203]

Recently, an article in the *Houston Chronicle* reported that, "Consumers…are in for a shock as retail prices have soared in anticipation of hot weather, potential power shortages and spikes in wholesale electricity prices."[204] "The increase in retail rates come as companies prepare for surging prices in the wholesale electricity markets where they buy their power. Forecasts of higher than normal temperatures and record power demand are coinciding with the shutdown of at least three coal-fired plants, leading to concerns that temporary shortages on the hottest summer days could send wholesale prices, which typically average less than $50 per megawatt hour, spiking to $3,000 per megawatt hour or higher."[205] Consumers who signed up with teaser rates, were on variable-rate contracts, and even one-year fixed rates are all vulnerable to price fluctuations (the latter increasing by 20 percent in the last year) [ss, 206] Thus, even Texas, which the ABACCUS report touted as "the

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[ss] Variable-rate plans fluctuate with the market, allowing some consumers to realize cost savings when the market price decreases but can increase under certain conditions, such as extreme heat or cold, leading to uncertainty. Fixed-rate plans do not change over the terms of the contract, which can ensure certainty but do not allow the consumer to take exploit advantageous conditions, such as when market prices decrease. See, for example: Eisenbach Consulting, LLC. "Variable vs. Fixed Rate Electricity Plans." *Electric Choice*. April 14, 2015. Available: https://www.electricchoice.com/blog/fixed-variable-electricity-plans/.

competitive residential electricity market leader for the eighth consecutive year" in 2015, is not invulnerable to volatility in the market. One report cited previously contended that the market is most efficient when retail electric rates approximate wholesale electricity costs.[207] That would suggest that the Texas market is working as designed, but both the upside and the downside for consumers is the exposure to market fluctuations in wholesale electric costs.

Lastly, we conclude this sub-section with a discussion of macro-level effects on consumers. Reports from official bodies in several states have found that retail electric choice has contributed to aggregate losses in consumer savings. The New York Public Service Commission conducted a 30-month study ending in June 2016 and found that consumers who switched to a competitive supplier, rather than remaining with the local utility, paid more than $820 million more for electricity and gas than had they remained.[tt, 208] The Office of Consumer Counsel in Connecticut found that that state's consumers paid approximately $58 million more by using retail suppliers in 2015 than had they retained default service options with the local utility.[209] In Rhode Island, a report on the docket of its Public Utilities Commission indicated that, over the period 2013 to 2017, default service costs were $56 million less for Rhode Islanders, versus those who chose competitive suppliers.[210] And a report commissioned by the Massachusetts Attorney General's Office showed "that Massachusetts consumers in the competitive supply market paid $176.8 million more than they would have paid if they had received electric supply from their electric company during the two-year period from July 2015 to June 2017."[211] Pursuant to that report, in March of 2018, Massachusetts Attorney General Maura Healey called for an end to residential retail electric choice in the state.[212]

Note that these reports have been criticized by supporters of retail electric choice, particularly with respect to Standard Offer Service (SOS). For example, with respect to the Massachusetts case, Jon Wellinghoff, a former chair of the Federal Energy Regulatory Commission and a consultant to ECI (Yes on Question 3) said that "the Massachusetts experience will not apply in Nevada. The incumbent utility in Massachusetts was allowed to compete with REPs and that gave its 'monopoly distribution service' undue leverage....And Nevada's as yet unwritten market rules will put stronger consumer protection laws in place and provide greater market transparency."[213] Similarly, the Retail Energy Supply Association (RESA) has taken exception to the Massachusetts report:

> RESA criticized the move saying that the **two-year timeframe considered in the report incorporates "two periods of steep basic service rate declines and ignores the period of sharp basic service rate increases prior to July of 2015**," disregarding rational consumer behavior before that period. The association also said that the report does not consider the differences in types of product offerings from competitive suppliers or the reason why customers opted for a product. RESA presented an analysis on May 8 saying that suppliers could have saved residential customers nearly $93 million in the first four months of 2018 if customers switched to the lowest available rate.[214]

[tt] New York offers retail electric and gas choice. Source: New York State. "NYS Power To Choose: About." Available: http://documents.dps.ny.gov/PTC/home/home. | "Remaining with the local utility" refers generally to Standard Offer Service (SOS), discussed in Section IV.

Renewable Energy

Text Box 2. Renewable Energy Arguments (from Official Websites)[215]

YES on 3: "Energy choice will expand Nevada's clean energy options."
NO on 3: "Threatens Nevada's progress toward a clean energy future."

Restructuring and Renewable Energy: Is There a Relationship?

As of 2016, Nevada's utility-scale net electricity generation from geothermal energy ranked second in the nation, and its utility-scale net generation from solar energy ranked fourth in the nation.[216] However, approximately 88 percent of the fuels Nevada consumes come from out of state.[217]

Question 3: The Energy Choice Initiative does not explicitly require that more renewables are integrated onto the grid.[218] But, would restructuring promote increased renewables or hinder their development? An exhibit which accompanied testimony before the Governor's Committee on Energy Choice (CEC) indicated that, "Customer choice will not, and was not intended to, by itself guarantee more clean energy or the resulting economic benefits."[219] A post written to inform companies about renewable energy procurement stated, "The value proposition associated with large-scale renewable energy projects – lower costs, reduced future price risk, lower GHG [greenhouse gases] and other strategic benefits – is available, no matter the regulatory regime for your organization's U.S. footprint."[220]

According to the industry experts with whom the Guinn Center spoke, neither a restructured model with retail electric choice nor the current vertically integrated utility structure provides unequivocally a more optimal pathway to delivering more renewable energy onto the grid.[221] In fact, these experts assert, there is no correlation between restructuring, or lack thereof, and increased renewables: the type of market model has no bearing on increased renewable energy.[222] If one of the primary objectives is to increase renewables consumption in Nevada, that is possible under both retail electric choice and a vertically integrated utility, though one expert stated that a competitive retail market would be more "nimble" in the context of rapidly advancing energy technologies.[223] And neither the adoption of the former nor the retention of the latter would undermine that goal.[224] However, recent data suggests that corporations in wholesale markets have been able to access renewables.[225]

There are several mechanisms that promote clean energy, including policy measures, such as increasing the RPS, and investments that would enhance the existing infrastructure. Neither of these is related, specifically, to restructuring.

Renewable Portfolio Standard (RPS)

Nevada has a Renewable Portfolio Standard (RPS) which "establishes the percentage of electricity sold by an electric utility to retail customers that must come from renewable sources."[226] Pursuant to *Nevada Revised Statutes* (NRS) 704.7821, the percentage of renewable energy must reach 25 percent in 2025.[uu, 227] According to Nevada's *2017 Status of Energy Report*, the state RPS mandate was 20 percent 2017, and NV Energy "was on course to easily surpass that standard" for the year, with an actual RPS of 41 percent.[228]

In interviews with the Guinn Center, the vast majority of industry experts stated that the most significant factor in increasing renewables is the RPS.[229] As the RPS, which mandates compliance, increases, the greater the percentage of renewables that must be sold to consumers; this would be true under retail electric choice or the vertically integrated utility.[230] The RPS effectively compels an entity to invest in renewable development across the three major components of electricity delivery (e.g., generation, transmission, distribution) to meet the standard.

However, as another industry expert shared, given that the RPS is considered the most robust institutional tool to promote renewables, it is possible that a vertically integrated utility would serve that end more efficiently.[231] A single entity might have the financial resources to execute 30-year PPAs, a willingness and/or interest in investment, and the ability to exploit economies of scale.[232] And because there would be only one major utility and one regulatory body, renewable projects could be approved and fossil fuel generation could be retired in accordance with new installations cost-effectively and in a timely fashion.[233] In other words, the RPS, as a regulatory matter, and a vertically integrated utility, by virtue of its structure, are consonant with one another.

Amanda Levin, a representative from the Natural Resources Defense Council (NRDC), a non-profit environmental advocacy group, presented evidence to the CEC showing that many states that have restructured did so in concert with increasing their RPS.[234] She asserted, "In the last two years, there have been ten significant increases to Renewable Portfolio Standards, and seven of those are restructured states: New York, Michigan (which has limited access to retail choice), Maryland, Rhode Island, Illinois, Massachusetts, and Washington, D.C. The three states that are not restructured were California, Oregon, and Hawaii. So not only was restructuring interconnected with retail choice, but, in fact, these retail choice states have continued to increase their Renewable Portfolio Standards and expand upon them in the last two years, much more so than other states."[235] That said, one industry expert indicated that the relationship between restructuring and the RPS is not clear-cut: the increased RPS in retail electric choice states did not result from a policy choice regarding market design or for regulatory reasons but rather constituted a political bargain to garner support for restructuring from environmental advocacy groups.[236]

[uu] On July 13, 2018, the Nevada Secretary of State announced that the Renewable Energy Promotion Initiative (Question 6) qualified for consideration by voters at the November 6, 2018, General Election. If a majority of voters approve Question 6, Nevada would be required to double its Renewable Portfolio Standard from 25 percent by 2025 to 50 percent by 2030. (*Source*: Associated Press. "Renewable Energy Ballot Measure Qualifies for Nevada Ballot." *Reno Gazette Journal*. July 13, 2018. Available: https://www.rgj.com/story/news/politics/2018/07/13/renewable-energy-ballot-measure-qualifies-nevada-ballot/783390002/.)

The Auction Process, RPS, and Renewable Energy Credits

One argument for the possible relationship between retail electric choice and the promotion of renewables is that, as a theoretical matter, customers would not be locked in to local generation or whatever power source the utility selects; that is, customers could choose renewable options.[237]

But, here we refer to the previous discussion in Section II regarding the role of independent power producers (IPPs) in the wholesale electric market and competitive suppliers as brokers between that market in the retail electric market. Competitive suppliers do not produce energy themselves but merely purchase it from the IPPs. It is up to the IPPs to supply the actual energy. Renewable energy may not be available from the generation assets participating in the auction process, or the ISO operator may not select renewables in establishing the clearing price, where the "cost of the very last generating plant needed to supply power in a given hour sets the system cost"; once that is set, the system operator tells generators if they are not needed.[238]

The relevance for this discussion of retail electric choice is that if there is enforced compliance with an RPS, but there are insufficient generation assets to meet those requirements and/or the ISO does not select bids from renewable producers to satisfy the requirements in a choice context, then competitive suppliers must purchase Renewable Energy Credits (RECs). "RECs are the environmental value of renewable generation and can be bought and sold on a market. RECs do not need to be tied with consumption of the actual renewable generation" and "[m]ost restructured states used RECs…and Alternative Compliance Payments (ACP) to meet RPS requirements."[239] A report issued by the National Renewable Energy Laboratory (NREL) states that, "Unbundled RECs remain the largest source of green power sales."[vv, 240]

The argument that retail electric choice will result in the integration of more renewables on the grid is flawed insofar that it does not account for the RPS and the auction process in organized wholesale markets:

1) The presence of competitive suppliers operating in a retail choice market cannot alone deliver more renewable energy onto the grid, as the burden falls more heavily to the IPPs and the ISO.

2) RECs are paper transactions only, so while a competitive supplier may promise a contract with 100 percent renewables, it does not follow that consumption of renewable generation will be actualized, as these suppliers cannot control transactions in the wholesale electric market, and they do not own generation assets themselves: a "100 Percent Renewable" contract means only that the supplier complies with that service offering by committing to

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[vv] An explanation (i.e., RECs, simplified): "Joe's Solar puts a 5 kilowatt system on your roof and sells you the electricity under a power purchase agreement. Because Joe owns the panels, he gets credit — in the form of RECs — for the 7000 kilowatt-hours (kWh) of renewable electricity it produces each year. Meanwhile, Bob's all-fossil utility wants to 'green up' so it buys the RECs from Joe to match with its coal or gas-fired generation. Then Bob can claim that 7000 kWh of its power is renewable." (*Source*: Severin Borenstein. "Double Counting Virtue." *Energy Institute Blog*. Energy Institute at Haas, University of California, Berkeley. January 11, 2016. Available: https://energyathaas.wordpress.com/2016/01/11/double-counting-virtue/.)

the purchase of RECs.[241] From a technical standpoint, "The renewable energy attributes are separate from the physical electricity, which becomes indistinguishable and untraceable once it is placed on the grid. As a result, the use of specified renewable energy sources can only be determined contractually…[.]"[242]

3) Some industry experts argued that a relatively high RPS could act as a deterrent to market entry or lead to market exit by competitive suppliers if the costs of energy, coupled with the obligation to purchase RECs, is cost-prohibitive.[243]

Energy Infrastructure: Prospects and Challenges

If the onus for increased renewable energy development is placed on the IPPs in a restructured market, then Nevada could be confronted with a collective action problem. What kind of incentives would the market offer for the construction of clean energy generation assets? Why would any single producer absorb these concentrated costs while pursuing profit-maximizing ends? How would an increased RPS interact with those decisions? Could the Nevada Legislature mandate a specific amount of renewable energy generation from IPPs? These questions largely remain unanswered at the time of this writing, but Pennsylvania may provide some insight into the process.

In 2004, Pennsylvania Governor Edward Rendell signed the Alternative Energy Portfolio Standards Act into law.[244] It mandated "that electric distribution companies [utilities] and electric generation suppliers [IPPs] include a specific percentage of electricity from alternative resources in the generation that they sell to Pennsylvania customers."[245] Specifically, the law requires that approved renewable or alternative sources provide 18 percent of electricity sold by 2021.[246] The state had begun allowing full retail access for all customers as of January 1, 2000.[247] This means that Pennsylvania established its RPS during the initial phase of restructuring.

Since that time, the state has witnessed growth in wind farms and solar facilities, and that generation largely has been self-financed:[248]

> The 15,000 megawatts of new generation in Pennsylvania was built entirely with private investment of approximately $15 billion. That large investment was made without any contribution from or risk to utility ratepayers. The companies and their shareholders building the new generation took all the risk of the investment. This shifting of risk from captured utility ratepayers to shareholders is an enormous benefit to utility customers.[249]

In Nevada, new renewable generation assets may come online irrespective of whether Question 3: The Energy Choice Initiative passes in November 2018 or not. Switch, a technology infrastructure corporation, which is headquartered in Las Vegas, announced the planned construction "of the single largest solar project portfolio in the United States."[250] It would do so in partnership with Capital Dynamics, a global asset manager, and the project would supply one gigawatt (gW) of solar generation via projects to be built in northern and southern Nevada.[251]

NV Energy's "2018 Joint IRP [integrated resource plan]," which has a 20-year planning horizon (i.e., 2019-2038), would add "1,001 megawatts of new, solar generating facilities….The plan contains [six] projects located in Clark, Humboldt and Washoe counties."[ww, 252] As 1,000 megawatts (mW) is the equivalent of one gW, NV Energy intends to construct the equivalent amount of solar generation as Switch. Moreover, the 2018 Joint IRP "proposes approximately $20 million of investment to bring the output of new solar PV [photovoltaic] facilities to customers. In addition, the plan proposes to expand grid improvement efforts by upgrading 230 kilovolt-transmission facilities at a cost of $720 thousand."[253] However, were Question 3 to pass, NV Energy would not develop the expanded renewable energy projects but would only execute a limited, RPS-compliance plan only to meet Nevadans' needs through 2023.[254]

The issue of generation assets, at least in the short term, appears to be settled: new renewable energies could be supplied regardless of the regulatory framework, reinforcing the assertion that restructuring is not associated, on its own, with increased renewables.

Organized Wholesale Markets/ISOs and the Resource Mix

However, restructuring would add one additional layer of uncertainty to the renewables question. As noted earlier, a precondition for the establishment of retail electric choice is participation in a preexisting organized wholesale market or the adoption of a new one. The vertically integrated utility, in which the supply chain is managed by a single entity (NV Energy) and regulated by a single body (the PUCN), provides certainty around generation assets, future plans, and the ability to meet demand with supply. These subjects are addressed in NV Energy's 2018 Joint IRP.[255] If Question 3 were to pass, the Nevada Legislature would need to decide whether to participate in an established ISO or form its own. Were Nevada to join an ISO, its generation assets would be commingled with those of other members through regionalization.[256] The ISO selection decision, then, contributes to the uncertainty around renewable energy deployment, as ISOs' fuel portfolios can vary widely.

Based on testimony before the CEC, it seems that the two most likely options for membership are the California Independent System Operator (CAISO) or the Southwest Power Pool (SPP).[xx, 257] The Southwest Power Pool member states are: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.[258]

To provide a comparison of resource mixes in the potential organized wholesale markets, the Guinn Center retrieved data from EIA on net generation in Nevada (as the current baseline), California, and the SPP states. Net generation is defined as: "The amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries."[259]

While net generation is not equivalent to consumption, and it does not capture precisely how the mixing of fuels within organized wholesale markets would translate to the end-use customer, it is a rough approximation of the fuel portfolio prospects that lawmakers would need to consider, should

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[ww] NV Energy's IRP is a triennial "plan to increase its supply of electricity or decrease its demand," as required by Nevada Revised Statutes. § 704.741. See: Public Utilities Commission of Nevada. n.d. "Integrated Resource Plan Integrated Resource Plan ('IRP')." Slide 2 of 14. Available: http://www.sec.nv.gov/docs/puc_presentation_090707.pdf.

[xx] Section IV discusses possibilities for organized market establishment and/or participation, and, where relevant, potential costs and time frames therein.

Question 3: The Energy Choice Initiative pass in November 2018. Figure 9 displays net generation in Nevada for 2017, with energy sources computed as a percentage of the total; Figure 10A provides a similar depiction for California (as a proxy) for CAISO; and Figure 10B represents an aggregation of energy sources by SPP member states and then calculated as a percentage of the total.[260]

As the pie charts show, there is considerable variation in fuel portfolios. Nevada generates a substantial amount of natural gas (70.2 percent) and a lesser, though not insignificant quantity of renewables (20.2 percent). The resource mix differs considerably across California and the SPP states: less than half of California's net generation comes from natural gas (42.7 percent) and under one-third from renewable energy (27.1 percent); in the SPP states, coal dominates generation (39.6 percent), followed by natural gas (30.0 percent), and then renewable energy (16.6 percent).

The Nevada Independent conducted an interview with Michael Brune, the executive director of the Sierra Club, an environmental organization, and Brian Beffort, the Sierra Club's Toiyabe Chapter director, and a question posed by the news website explicates the regionalization conundrum: "The argument that is made on the solar side is it will help balance the West's resources and sort of distribute the energy out. But there's also the argument that's made that if you bring in states that have a more coal dominant portfolio, you're diluting the [renewable portfolio standards] that you have in California or Nevada."[261] Some reports have pointed to potential tensions between state-level mandates, such as variations in RPS and the authority of the ISO and/or FERC, observing that there is an underlying question of balance between state prerogatives and the imperatives of a centralized coordination regulatory apparatus that remains unresolved.[262]

Thus, the choice of organized wholesale market may shape the Silver State's prospects for its renewable energy future under retail electric choice, particularly as legislators would have to evaluate the complementarities (or lack thereof) that a preexisting ISO might offer.

Figure 9. Net Generation: Nevada, 2017

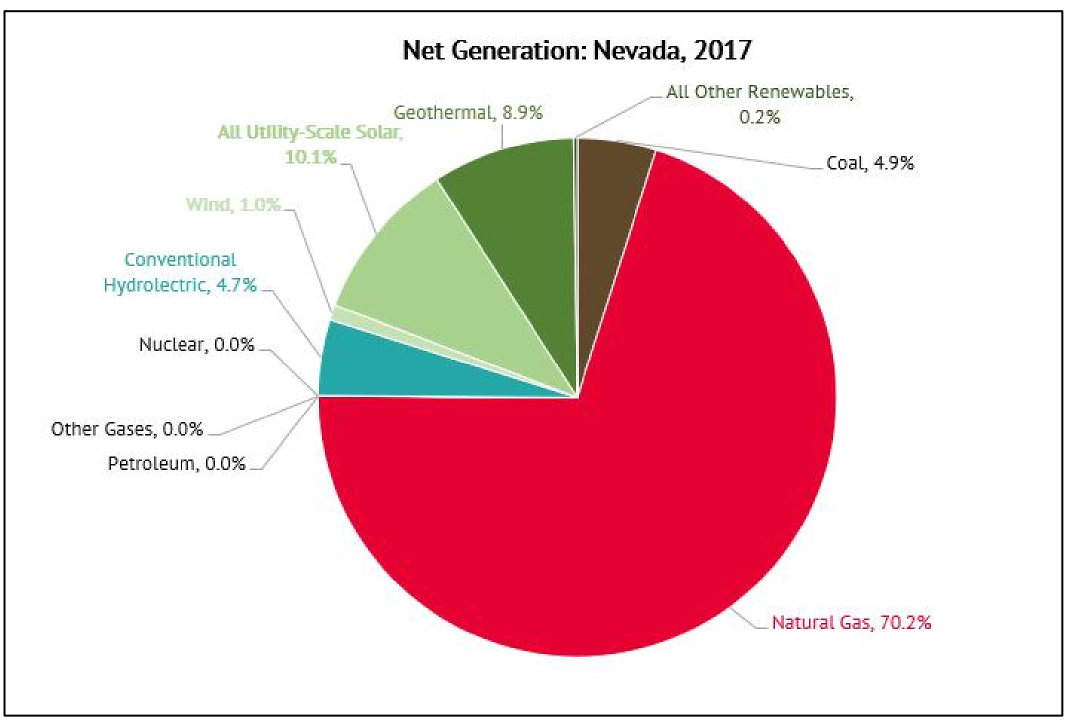


Figure 10A. Net Generation: California, 2017

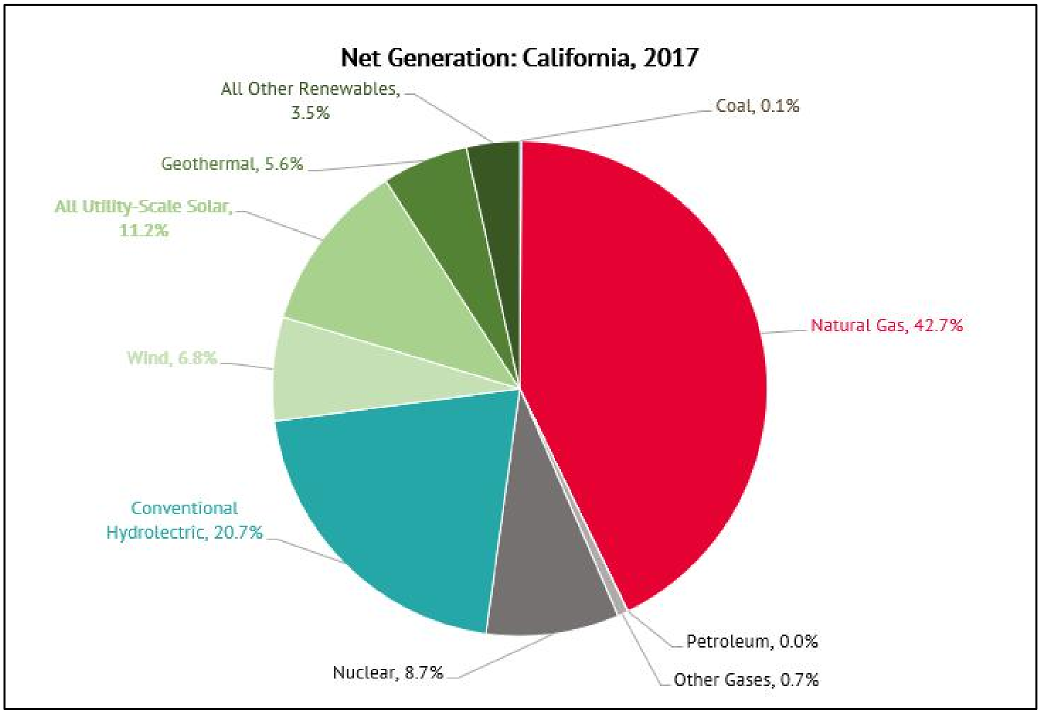
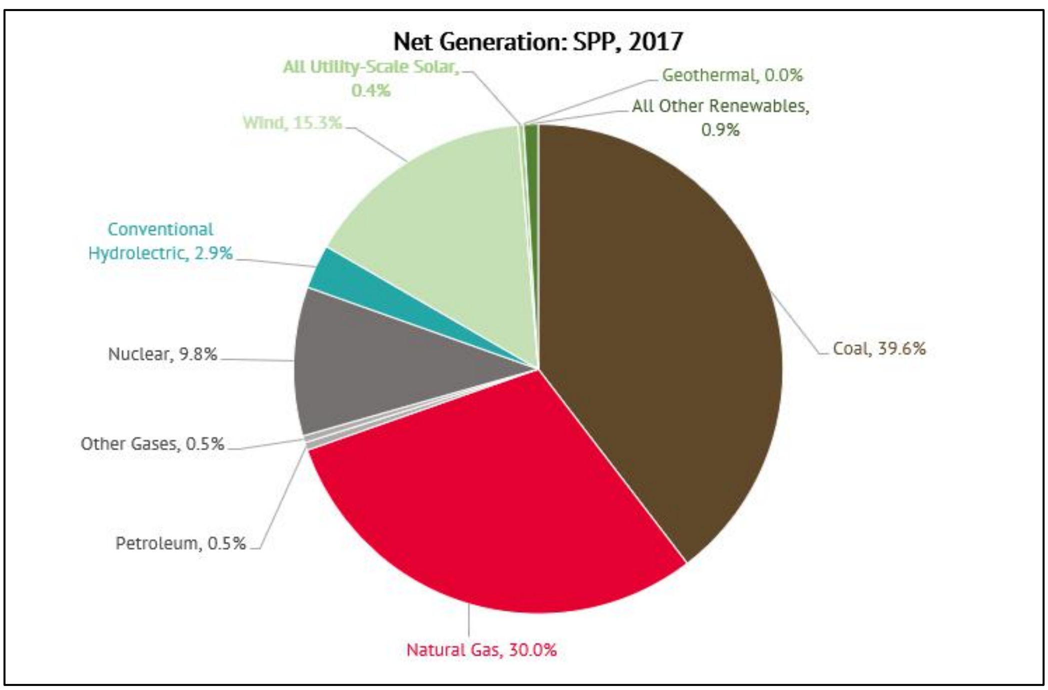


Figure 10B. Net Generation: SPP, 2017



IV. Additional Issues Related to Restructuring

This section addresses four additional issues associated with retail electric choice: organized wholesale markets (ISO creation or participation), divestiture/stranded assets, consumer impact, and implementation.

The organized wholesale markets sub-section (ISO creation or participation) discusses three options for Nevada, were Question 3: The Energy Choice Initiative to pass in November 2018 by a majority of registered Nevada voters. As testimony before the Governor's Committee on Energy Choice (CEC) suggests, the two most likely options for participation are the Southwest Power Pool (SPP) or the California Independent System Operator (CAISO). Alternatively, Nevada could establish its own independent system operator (ISO). Costs, time frames, and institutional dimensions vary with each option, and these are documented here, where available.

Divestiture and the related issue of stranded assets are addressed in the second sub-section. As we have noted previously and do so again here, the ballot initiative does not mandate divestiture, but many observers view this as a necessary outcome of restructuring. The incumbent utility's assets become "stranded" by virtue of divestiture and may be sold for a loss or a gain, which can translate into stranded costs or negative stranded costs (i.e., stranded benefits), respectively. Research reveals that retail electric choice states have encountered both stranded costs and stranded benefits, though many of these states were unable to forecast the amounts accurately in advance of the restructuring process. Current estimates for potential restructuring in Nevada range from $6.7 billion in stranded costs to $1.1 billion in stranded benefits. Any stranded costs likely would be borne by ratepayers in the form of a competitive transition charge (CTC), while stranded benefits could be passed on to ratepayers through rebates. We stress that these are estimates only that are subject to change through a valuation and asset purchase process.

In the consumer impact sub-section, we begin with a discussion of large commercial and industrial customers, as the distinction between these ratepayers and residential/small commercial customers illuminates the difficulties often faced by the latter in a restructured market. Residential and small commercial ratepayers typically are not knowledgeable about the intricacies of electricity procurement, and, as evidence from other states shows, this has contributed to market manipulation and customer exploitation. We close the sub-section with a description of Nevada's current institutional capacity for managing customer issues related to their electric bills.

The implementation sub-section examines experiences in other states with development of a competitive retail electric market. Here, we find that many states encountered implementation challenges, as enabling legislation and initial regulatory orders either contributed to adverse outcomes or could not anticipate unintended consequences, necessitating additional policy and/or regulatory interventions as corrective actions. The sub-section concludes with a discussion of the ballot initiative as a constitutional amendment, noting that if Question 3: The Energy Choice Initiative were to pass in November 2018, Nevada would be the only state to have used a constitutional remedy to restructure its electricity market. The implications of this procedural choice also are considered.

Organized Wholesale Markets (ISO Creation or Participation)

Testimony before the CEC suggests that Nevada currently has three options with regard to organized wholesale markets. In certain cases, preliminary estimates and time frames have been provided, but given that they are estimates only, there is no certainty as to the fiscal impact to Nevadans, who, based on the experiences of other states, are likely to bear the costs.[263]

The first option for the Silver State is creation of its own organized wholesale market as an ISO (e.g., NV-ISO). NV Energy projected an initial cost of about $100 million in testimony before the Legislative Committee on Energy on April 18, 2018.[264] Given that organized wholesale market participation is a prerequisite for the creation of a competitive retail choice market, it may be inferred that such a market would need to be established by July 1, 2023, pursuant to the ballot initiative.[265]

Second, Nevada could join the Southwest Power Pool (SPP). However, a potential problem with SPP is feasibility, as there is no direct transmission capacity between the SPP and the Nevada market, and it might take 10 years to build capacity.[266] That said, "…there are transmission facilities that go from Nevada through other states so fiscally we are connected."[267] An industry expert confirmed to the Guinn Center that "the 10-year infrastructure projection would be a good estimate if existing transmission could not be utilized and new transmission had to be constructed."[268] At the August 8, 2017, meeting of the CEC, Carl Monroe, SPP's Executive Vice President and Chief Operating Officer, responded to Nevada Attorney General Adam Laxalt's question regarding costs as follows: "…you can actually prepare an RFI [Request for Information] to request costs from us…so you have the information you need to make a decision."[269] At the time of this writing, it is the Guinn Center's understanding that no RFI has been submitted by the CEC to SPP.

A third option for Nevada is participation in the California Independent System Operator (CAISO). The State could be expected to spend about $250,000 to study the benefits of regionalization; less than $500,000 for incremental implementation costs to incorporate the NV Energy system (presumably, the wires); and $21-$27 million annually on a Grid Management Charge (GMC).[270] The foregoing comes with the caveat that all amounts are estimates only and are subject to change.[271] In particular, the GMC estimate "…does not include GMC costs to serve non-NV Energy related customers because the load data for such customers is not readily available to the ISO."[272] While this may be interpreted as reference to customers outside NV Energy's service territory, another possibility is that it cannot account for load data under retail electric choice as that is yet unknown. If NV Energy were to join CAISO, the scope of activities could take 24-26 months, but other factors "outside of the ISO's control" could affect the timeline.[273] It is not clear whether restructuring would change the timing projections. Lastly, it should be noted that the California State Legislature currently is considering a bill (Assembly Bill [AB] 813) that would transform the ISO into a regional organization and thus engender a corresponding change in its governance.[274] As one industry expert shared with the Guinn Center, the outcome of the bill might determine whether Nevada *could* join CAISO.[275] AB 813 currently is in committee before the California State Assembly.[276]

Divestiture and Stranded Assets

As noted in Section II, the ECI ballot initiative petition does not require NV Energy to divest itself of generation assets. If Question 3 were to pass, the Nevada Legislature would need to determine whether divestiture should be mandated. Some states required utilities to divest, while others merely encouraged it.[277] Citing data from 2004, one study found that utilities in all restructured states had divested their generation assets, at least in part (at that time, only Delaware, the District of Columbia, Maine, Massachusetts, New Hampshire, and Rhode Island were 100 percent divested).[278]

With divestiture comes the uncertainty of the cost of stranded assets. Stranded costs may be defined as, "…the decline in the value of electricity generating assets due to restructuring of the industry."[279] In other words, when a vertically integrated utility is required to divest, that is, sell its generation assets and PPAs, it may take a loss (stranded costs) or sell at a premium (negative stranded costs or stranded benefits). In mathematical terms, it may be expressed as: *Book Value* (accounting value/regulator value) – *Market Value* (economic value/competitive value) = *Stranded Cost*.[280] This means that projections may be made as to the book value of the assets, but they may not be realized at the time of the sale. External factors, such as the demand for natural gas, will play a significant role at the time of divestiture, as will the buyers' offer price for the purchase of assets that are effectively discounted by virtue of the legal requirement to divest.[281]

Incumbent utilities typically have been permitted to recover these stranded costs through a competitive transition charge (CTC), which is assessed until all costs have been paid. Most states levied the CTC on all ratepayers as a fee on top of the wires service, regardless of whether the customer had remained with the incumbent utility or switched to competitive supplier. As discussed in Section III, though, Michigan briefly experimented with an incentive that allowed ratepayers who switched to retail supplier to avoid the CTC.

Why are incumbent utilities permitted to recover stranded costs? The answer lies in what is called the "regulatory compact":

> …utilities in all restructuring states persuaded regulators that the implicit agreement between the regulator and the [vertically-integrated monopoly utility] IOU (commonly referred to as a 'regulatory compact') required that the utility be made whole for any lost asset value from restructuring. Nearly all the generation assets with market value below the IOU's remaining book value had been built with the approval, and in some cases mandate, of regulatory commissions, so it was generally concluded that to force restructuring without compensation for stranded assets would violate the regulatory compact. Most state restructuring schemes included a plan for 100% recovery by utilities of any stranded investment and the others aimed at nearly 100% recovery.[282]

We detailed several states' experiences with divestiture in Section III in the context of rate caps, freezes, and reductions, but we will reiterate some of the impact here, as well as add some data points; note that some states had multiple vertically integrated utilities prior to restructuring.

Texas's initial estimates of stranded costs ranged from negative $2 billion to more than $6.5 billion; after litigation, the total amount of stranded costs was $9.5 billion.[283] Montana sold its generation assets for $118 million over book value (i.e., a negative stranded cost), though it filed a request to recover about $23.8 million from a PPA that it could not divest, which FERC denied.[284] In New England, Connecticut's stranded costs were settled at $1.4 billion; Massachusetts had an approved stranded cost recovery of approximately $1.6 billion; and New Hampshire's stranded costs were $688.1 million. At the high end is Pennsylvania: across its seven utilities, final stranded cost allowances amounted to about $11.9 billion.[285]

Estimates of stranded assets have been provided for Nevada, though they diverge significantly. The PUCN estimates stranded costs in the amount of $4.1 billion, based on a 37 percent decline in the net book value of NV Energy's generating assets by 2023, and additional capital investments, if permitted, which could offset some of those losses. The PUCN's projections are lower than NV Energy's of $6.7 billion.[286] Stranded costs could include: (1) generation assets, such as power plants sold at below the remaining book value; (2) PPAs, fuel contracts, transmission contracts, and service contracts; (3) outstanding regulatory assets; (4) computer/data/electronic information and technology programs/systems; and (5) costs to retire debt and equity capital.[287]

On the other hand, an analysis presented to accompany Public Comment to the CEC on May 9, 2018, prepared by Mark Garrett, of Garrett Group, LLC, showed negative stranded costs (i.e., stranded benefits) of just over $1.1 billion.[yy, 288]

The range between a stranded cost of $4.1 billion and a stranded benefit of $1.1 billion is not insubstantial, and, while both are possible, as is something in between, neither represents the actual valuation or what a given buyer is willing to pay at the time of divestiture. And that cannot be quantified until the time of divestiture itself. These are merely estimates, and as one report asserts, "the values of electric generation assets change over time with market conditions."[289] The Texas case where projections were made for both stranded benefits and stranded costs but for which stranded costs actually exceeded the initial estimate—though the assets were resold for a profit under more optimal market conditions—should provide a cautionary tale.[290] Estimates, by definition, are uncertain, and the actual value is contingent on fluctuations in the market. Regardless, Nevada's ratepayers likely would have to pay any stranded costs, possibly through a CTC, and the time frame for recovery and the possibility of rate caps add to the uncertainty.

[yy] The ECI asked Mark Garrett to conduct an independent analysis of the impacts of the ECI. *Source*: State of Nevada, Governor's Committee on Energy Choice. "MINUTES: Testimony Before the Governor's Committee on Energy Choice." May 9, 2018. Available: http://energy.nv.gov/uploadedFiles/energynvgov/content/Programs/TaskForces/2017/CEC Minutes for 9 May 18 DRAFT.pdf.

Consumer Impact

Irrespective of market structure, the procurement of electricity exerts differential impacts across ratepayer classes.[zz] Large commercial and industrial (C&I) customers tend to enjoy lower rates, relative to their residential and small commercial counterparts, under both a traditionally regulated utility structure and retail electric choice.[291] As Figure 8B (Section III) indicated, in restructured states, C&I take-up of the competitive supply option far outpaces that of residential consumers. The reasons for this variation offer insight into the issues some residential ratepayers in restructured states have experienced when switching to retail suppliers.

[zz] Some clarification on ratepayer class is required for the discussion here, as "commercial" can have different meanings. Residential and small commercial customers typically are grouped together, as these classes have similar load shapes. Load shapes "refer to the varying amounts of electricity required over time." (See: U.S. Department of Energy, U.S. Energy Information Administration. "Electric Grid Operators Forecast Load Shapes to Plan Electricity Supply." July 22, 2016. Available: https://www.eia.gov/todayinenergy/detail.php?id=27192; note that load shapes tend to be more variable for smaller customers.) An additional reason for this sort of classification turns on level of understanding and sophistication with regard to their energy needs, which tends to be lower for residential and small commercial ratepayers. (*Source*: Paul Chernick, John T. Colgan, Rick Gilliam, Douglas Jester, and Mark LeBel. "Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers." Electricity Rate Design Review Paper No. 1. July 18, 2016. Available: https://www.seia.org/sites/default/files/Charge Without a Cause - Final - 7-18-16_0.pdf.) Large commercial and industrial customers have relatively flat load structures. (*Source*: U.S. Department of Energy, Federal Energy Regulatory Commission. 2015. "Energy Primer: A Handbook of Energy Market Basics." Page 43. Available: https://www.ferc.gov/market-oversight/guide/energy-primer.pdf.) And these ratepayers tend to have greater expertise in electricity procurement. (*Source*: Paul Chernick, John T. Colgan, Rick Gilliam, Douglas Jester, and Mark LeBel. "Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers." Electricity Rate Design Review Paper No. 1. July 18, 2016. Available: https://www.seia.org/sites/default/files/Charge Without a Cause - Final - 7-18-16_0.pdf.) The distinction is important, and, as such, we will treat residential and small commercial customers as one class, and large commercial and industrial ratepayers as another (we refer to the latter as C&I and/or "large customers").

One study suggests that residential ratepayers may be disadvantaged in a restructured market *because* of C&I customers, which are "cherry picked" by retail suppliers:[aaa]

> Alternative retail energy suppliers target larger customers first because of the large size of their loads relative to the transaction costs of serving them. Likewise, large electricity customers will seek the lowest available electricity prices. The result of customers being able to shift between the market and utilities that price according to cost of service is rent-shifting: when large electricity customers leave for lower market prices, the utilities' fixed costs of service are borne by their remaining customers; and when large electricity customers return to the utility when market prices are high, the remaining customers share with the big guys the relatively low utility costs. For customers able to shift between the market and utilities, this is a heads-I-win, tails-you-lose proposition, for which the remaining customers are the losers.[292]

This is not a consensus finding in the literature on retail electric choice, however. Most analyses attribute the higher switching rates among C&I customers to informational asymmetries and enhanced capacity. They do not construe restructuring as a zero-sum game but rather view C&I customers and residential customers as operating differently in the market. Even the authors of the abovementioned quote observe simply that large customers, by virtue of their size, enjoy certain benefits, such as the ability to dedicate staff time to investigation of supplier options and energy consumption decisions and to manage financial risks in ways that are inaccessible to residential ratepayers.[293] For example, some large customers may have the ability to hire an energy procurement specialist.[294]

This post summarizes the costs and benefits across ratepayer classes:

> To date, the biggest customers happen to be the biggest fans of retail choice. Within retail choice states, roughly half of commercial and industrial demand has switched to competitive

[aaa] The question of "cherry picking" is a thorny one and the subject of some disagreement. For example, in Michigan's survey regarding electric choice published in 2013, a joint response from Consumers Energy, DTE Energy, and MEGA (the utilities) stated: "…that AESs [alternative electric suppliers] have 'cherry picked' the markets and served only the large commercial and industrial customers with favorable load factors and more attractive credit profiles." (*Source*: Michigan Public Service Commission, Department of Licensing and Regulatory Affairs, and Michigan Energy Office. "Readying Michigan to Make Good Energy Decisions: Electric Choice." November 20, 2013. Page 16. Available: https://www.michigan.gov/documents/energy/electricc_report_440539_7.pdf.) On the other hand, the Retail Energy Supply Association (RESA), which advocates for vibrant and sustainable competitive retail energy markets as a better alternative for consumers than monopoly-protected utility regulation, dismisses the idea of "cherry picking." In a white paper, it notes that, "The assertion is that large commercial and industrial customers will reap the bulk of the benefits and that competitive suppliers will 'cherry pick.' However, the data show that prices for residential customers in competitive retail markets have been on a favorable track alongside the benefits that have accrued to C&I customers. While percentage changes in price differ among the customer classes in both the monopoly and choice states, this is due in part to the greater volumes and more constant demand characteristics of larger customers." (*Source*: Philip R. O'Connor, Ph.D. 2017. "Restructuring Recharged: The Superior Performance of Competitive Electricity Markets 2008-2016." Retail Energy Supply Association. Page 17. Available: https://www.resausa.org/sites/default/files/RESA_Restructuring_Recharged_White Paper_0.pdf.)

> suppliers, with small companies less likely to do so. Consumers representing about one-tenth of residential demand have done the same.
>
> This comes as little surprise, as the financial benefits of switching suppliers are proportional to a customer's size. In 2014, the average industrial customer's monthly electricity bill was more than $7,000, compared with $114 for a residential customer. If switching providers saves each customer 10 percent, then the industrial customer saves $700 and the residential customer just $14 per month. The former is enough to motivate sizable businesses to research and pursue alternative suppliers. But to save the equivalent of a pizza cost every month, the process for residential customers would have be fairly hassle-free.
>
> No surprise, some customers don't find it worth the hassle. Economists call the time and effort of switching providers "transaction costs." These include gathering information, evaluating providers and offers and making necessary arrangements with a new company (e.g., paperwork and communications).[295]

In other words, the transaction costs—the time and effort required to investigate retail electric choice options—may exceed the benefits that attend such relatively small cost savings for the average residential consumer.

The *Annual Baseline Assessment of Choice in Canada and the United States* (ABACCUS) report, which is published by Distributed Energy Financial Group (DEFG) LLC, a management consulting firm specializing in energy, points to an additional asset that C&I customers possess: knowledge. Large customers must know and understand energy, so they can evaluate options that align and/or reinforce their needs, such as the significance of electricity costs to their overall operating costs.[296] The report states, "Large energy consumers are sophisticated and they fully able to manage and sign a contract that best suits their operations."[297]

Capacity, information, knowledge, and sophistication, which are instrumental to commercial and industrial (C&I) customers' ability to flourish in a restructured market, tend not to be hallmarks of residential and small commercial customers, at least with respect to energy decision making. Unless a given customer has resided in a retail choice state, that individual's typical encounter with electricity procurement is what the vertically integrated utility has provided to him. Learning curves can be steep, as some of the experiences from other states demonstrate. Additionally, the president of an electricity shopping website also has explained that there is a language disconnect: for example, the electricity industry uses terms like kilowatt-hours, while customers conceptualize their electricity as monthly bills or the estimated cost to set the thermostat at a particular level.[298] Also, corporations have technology and access to information that has enabled them to shift loads, enter into demand response agreements, and take advantage of variable rates.

According to a website that helps customers sign up for electric service in restructured states, there are six common issues that figure in the most recorded complaints: (1) unknown fees; (2) poor customer service; (3) meter reading; (4) slamming and cramming ("Cramming is the illegal act of placing misleading charges on your bill that you did not agree to. Slamming is the process of switching your energy service to another provider without your permission[.])"; (5) switch hold rules, or the inability to switch retail providers until a back bill is paid in full; and (6) fluctuating prices.[bbb,299]

The last of these, fluctuating prices, is where informational disadvantages are greatest for residential customers. "As many consumers know, when you sign up for a new energy plan you will typically be given the option between fixed or variable rate energy plans. Many customers sign up for variable rate plans, either because they are able to lock in low prices, or because they do not come with as stringent of contracts. However, variable rate plans can change at any moment, in fact they can change any day. Just as gas prices and the stock market fluctuate, so does the energy market. Customers tend to complain when their energy prices go up drastically with the market, but this is a risk that customers take when they sign up for a variable rate plan. If you like to diligently plan how much of your budget will go to energy costs, then choosing a fixed rate plan is a better option. There isn't as much risk involved, and you will always know how much per kWh you will be spending each month."[300]

In fact, many residential customers, when first introduced to retail electric choice (or even later) are unfamiliar with variable-rate contracts versus fixed-rate contracts for electricity.[301] The Maryland Public Service Commission fielded 1,000 customer complaints regarding energy suppliers in 2013, which represented a 50 percent increase over the previous year.[302] Amongst others, the complaints involved price spikes (typically associated with variable-rate contracts), early termination fees that mounted into hundreds of dollars and for which customers were unaware, and slamming.[303]

This report presented evidence in Section III that showed that residential and commercial customers in Philadelphia and Pittsburgh were paying 40 percent to 56 percent less in 2016 than they did in 1996. But in 2014, at the residential customer level, anecdotes emerged about high electricity bills in Pennsylvania.[ccc] That year, 53,559 Pennsylvania electricity consumers returned to the default service option provided by the utility, amidst "a flood of consumer complaints to the state attorney general and utility regulators."[304] In that same year, Pennsylvania Attorney General Kathleen G. Kane, along with the Bureau of Consumer Protection and the Office of Consumer Advocate "filed joint complaints with the Pennsylvania Public Utility Commission against [the] five electric suppliers after receiving thousands of complaints from state residents saying their monthly electricity bills rose by as much as 300 percent over the winter."[305] The Attorney General's office "received 42,603 telephone calls and 7,551 consumer complaints about the electricity spikes."[306]

Similarly, the New Jersey Attorney General, Division of Consumer Affairs, and Board of Public Utilities filed a lawsuit against three retail suppliers in 2014, citing these companies' promised monthly savings that were fictional in practice; consumers experienced "skyrocketing" energy bills during a

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[bbb] The site is Texas-specific but is applicable to other states, as well.

[ccc] For example, a couple in Pennsylvania received a $634.12 bill, which was about five times higher than normal. "The bill was the result of a variable rate plan that spiked when severe cold weather caused a volatile swing in wholesale electric prices. For the next month, the Lehmans turned off lights and didn't use the stove or the dryer." (*Source*: Katelyn Ferral. "Variable-Rate Electricity Contracts in Pennsylvania Can Cost Customers Plenty." *Pittsburgh Tribune-Review [TribLive]*. November 19, 2014. Available: https://triblive.com/business/headlines/7069990-74/variable-customers-rate.)

"long and cold winter."[307] The suit also alleged that the retail suppliers engaged in deceptive tactics, such as slamming, and "other unconscionable commercial practices."[308] Altogether, there were 1,463 consumer complaints about the companies.[309]

In comment before the New Jersey Board of Public Utilities, the AARP, a non-profit, nonpartisan organization which represents people aged 50 and over, cited a "misrepresentation of prices, the use of variable rates that are not predictable or even plainly stated, teaser rates, the renewal of fixed rate contracts into variable rate contracts without affirmative customer consent, and a host of telemarketing and door to door activities that confuse customers and take advantage of their lack of education and understanding of the terms being proposed to them in a hard sell marketing technique."[310] The organization also observed that, rather than the 5 percent to 15 percent price reductions that people were promised, many customers saw electricity bill increases of 34 percent.[311] Additionally, the AARP raised concerns about disclosure on variable rates, stating that language such as "based on wholesale market conditions" is not informative in helping customers predict their next bill.[312]

As discussed in Section III, in 2007, Illinois enacted legislation that provided $1 billion rate relief to offset losses resulting from market manipulation and excessive power prices by wholesale suppliers.[313] Challenges in the state have persisted since that time. The Illinois' Citizens Utility Board, a non-profit, nonpartisan organization that represents the interests of that state's residential utility customers, issued a report in 2014 that warned consumers about exorbitant rates, disappearing low introductory rates, extra fees, "punishing" exit fees, and high-pressure sales tactics.[314] Some customers were charged rates up to six times higher than they would have paid under the utility's default service option.[315]

Several states provide guidelines to consumers regarding the selection of retail suppliers. They propose questions that customers should ask before signing a contract, and there are striking similarities across states. As an example, Figure 11 presents a screenshot from the Maryland Attorney General's website.[316]

Texas's "Power To Choose" website's recommendations are similar but, amongst others, also suggest that the consumer ask whether transmission and distribution are included and what the consumer will "pay per kilowatt hour (kWh) of electricity based on 1,000 kWh of average monthly usage[.]"[317] Pennsylvania's "PAPowerSwitch" website adds some additional questions, such as: whether the supplier is licensed by the Pennsylvania Public Utility Commission, how the price compares to the default service option provided by the incumbent utility, whether all taxes are included in the supplier's price, and if there is a switching fee, and more.[318]

The residential retail electric choice experience in other states has had its complications. Many consumers have lacked the expertise to make informed decisions about retail suppliers. That the states have provided official sources to help with the process speaks more to the obstacles that consumers have faced than to a facilitation of the process of retail supplier selection. In addition, a recurring theme is that consumers have not conceptualized well the distinction between variable-rate and fixed-rate contracts, and, relatedly, the impact of wholesale electric prices on the former.

During extreme and persistent adverse weather, such as long winters, many residential customers were adversely affected.

Figure 11. Maryland Attorney General: Choosing Your Residential Electricity Supplier

Maryland Attorney General: Choosing Your Residential Electricity Supplier

Advice for Evaluating Offers from Electricity Suppliers

Take your time to check out offers. You may receive offers from electricity suppliers through direct mail, telemarketing, advertising, and over the Internet. Read offers carefully and ask the supplier questions. You may have to commit to a fixed-term contract when you sign up with an electricity supplier. Therefore, be sure you like the terms of the offer. Questions to ask a supplier:

- Is the energy price fixed or can it fluctuate month to month? Does it vary by amount used or time of use?
- What is the length of the contract? Is there an early termination fee or other fee if you switch to another supplier before the contract period is over? How much notice is required to switch suppliers?
- Will the contract automatically renew at the end of the term? How much notice must you give if you don't wish to renew?
- How is the electricity generated - coal, gas, nuclear, hydro, etc.? What percentage of the fuel source is renewable, and what are the emissions levels?
- Is there a deposit or sign-on fee? A fee for late payments? Any other fees?
- Will you be billed by the supplier or by the electric company? Will you receive two separate bills or one combined bill?

However, we caution the reader not to interpret these experiences as predictive for Nevada should Question 3 pass. The intention simply is to report the consumer impact in other states so that Nevada's residents are aware of some potential pitfalls. If a majority of voters decide in favor of restructuring the electricity market, the Nevada Legislature and Governor will need to assess how robust our institutions for consumer protection are in their current form.

Currently, for example, the Public Utilities Commission of Nevada (PUCN) website states that customers who have a complaint about service provided by the regulated utility first should contact the utility's customer service representative for resolution, and barring a satisfactory response, should escalate the complaint to a supervisor from the utility.[319] Should the customer remain dissatisfied, he can contact the PUCN's Consumer Complaint Resolution Division.[320] The Bureau of Consumer Protection (BCP), under the auspices of the Nevada Attorney General and Consumer Advocate, "advocates the consumer's voice in cases involving the rates and service of privately-owned utility (telephone, electric, and natural gas) companies before the PUCN…[.]"[321] The BCP does not represent individual consumers, however.[322] Nevada Consumer Affairs, which is a division of the Department of Business and Industry, does not take consumer complaints on matters related to the regulated utility.[323]

It is not clear how or if these procedures would change in a restructured market, but it appears that one dimension of implementation might entail the establishment of some sort of apparatus to manage potential consumer complaints regarding retail suppliers or the augmentation of authority by a preexisting institution, such as the PUCN, BCP, or Nevada Consumer Affairs.

Implementation

The electricity system is especially complex, and the regulation of it is complicated. States that have restructured have reworked their legislation and regulatory frameworks to provide robust markets for choice. The restructuring process can be lengthy, given all the moving parts. Many states have encountered implementation hurdles (e.g., market imperfections) that necessitated an expanded role for the government. For example, an exhibit presented to accompany testimony before the Governor's Committee on Energy Choice (CEC) on August 23, 2017, stated that, "Restructuring takes time. For example, in Pennsylvania, this was a 16 year process. This may seem extreme but you have to not only have a structure in place but also deal with stranded costs in a transition to a competitive retail generation market[.]"[324] And at the first meeting of the CEC, Josh Weber, serving as counsel to the Energy Choice Initiative/Nevadans for Affordable Clean Energy Choices (i.e., Yes on Question 3) indicated that "most states have been doing it [retail electric choice] for a few decades but are still evolving and getting it right."[325]

We want to be clear, however, in asserting that the historical experiences of other states are meant for illustrative purposes only. We are not asserting that Nevada would confront these challenges, were Question 3 to pass. That said, it is important to document them so that residents are aware of what has occurred elsewhere and thus consider the implications for the Silver State.

A synthesis of case studies in four states in different regions—Illinois, Montana, New Jersey, and Texas—reveals that multiple pieces of legislation and/or regulatory orders were required to address the unintended consequences of restructuring. The report states, "New forms of market/government intervention to address market failures often have been necessary."[326] Illinois is emblematic in this regard: "First, the deregulation process was protracted and highly controversial, and included years of legislative debate, as well as a high-profile complaint and intervention by the state attorney general. Second, the turmoil associated with deregulation in Illinois—political, legislative, rate volatility, and other—reflected a lack of confidence in the ability of deregulation to ensure affordable, reliable power. This led Illinois policymakers to create new public entities and expanded roles for government in the purchase and sale of electricity in Illinois, essentially adding more regulation."[327] Illinois released four investigative studies, enacted two pieces of legislation, and put four regulatory orders in place by 2002.[328] It also enacted legislation in 2007 that required the aforementioned $1 billion in rate relief and created the Illinois Power Agency for the procurement of power for residential and small commercial customers of the incumbent utilities.[329]

One study from 2003, released during the initial phase of restructuring for most states, documents the implementation process in each to that point. Some examples: in Connecticut, the regulatory authority issued a report in 1995 that recommended restructuring, with a gradual move to retail competition; enabling legislation was enacted in 1998, and four additional regulatory orders regarding divestiture, Standard Offer Service, and consumer regulation were put in place by 1999.[330] Delaware required one piece of legislation and two regulatory orders through 1999.[331] The District of Columbia completed two investigative studies, passed one piece of legislation, and issued eight regulatory orders by 2001.[332] Likewise, Maine released one investigative study, enacted a single piece of legislation, and effectuated nine regulatory orders through 2002.[333]

On the other hand, New Jersey produced one investigative study, three pieces of legislation, and seven regulatory orders by 2000.[334] New York had three investigative studies, three pieces of legislation, and six regulatory orders through 2001.[335] Ohio conducted one investigative study, enacted one piece of enabling legislation, and issued twelve regulatory orders through 2002.[336] Texas released six investigative studies, enacted four pieces of legislation, and implemented nineteen regulatory orders by 2002.[337] As one report notes, though, the state did not anticipate certain issues in its enabling legislation; they only came into full view during the implementation phase and include information technology struggles, setup of the provider of last resort (i.e., the safety for those instances in which the retail supplier cannot continue service), costly market redesign (related to issues regarding market manipulation and a need to redesign the wholesale market), and stranded costs.[338]

Michigan perhaps best exemplifies the challenges surrounding implementation of retail electric choice, as its plans were considered carefully yet thwarted through the process. In 2000, two companion pieces of legislation—Public Act 141 and Public Act 142—were enacted to enable restructuring.[339] Five regulatory orders had been issued through August 1999 to lay the groundwork for a retail electric choice market.[340] By 2002, the Michigan Public Service Commission implemented 25 additional regulatory orders.[341] Michigan requires annual reports on the status of electric competition in the state. Its report for 2006 states that "the Commission issued 40 orders to further establish and implement the framework for Michigan's electric customer choice programs and the provisions of 2000 PA 141."[342] As detailed in the report, the 40 orders concerned implementation:

- "Two orders approving new AES [Alternative Electric Supplier] licenses;
- Two orders approving relinquishment of AES licenses;
- Five orders addressing stranded costs;
- Two orders adjusting securitization charges;
- One order closing a docket on implementation costs;
- Six orders addressing electric generation and transmission issues;
- Five orders relating to energy efficiency and renewable energy programs;
- Five orders investigating Code of Conduct and rule violations and adjustments;
- Two orders adopting a new power supply cost recovery method;
- Two orders distributing the Low-Income and Energy Efficiency Fund;
- Two orders piloting a PAYS® program;
- Four orders protecting customers from higher rates and service provider disputes;
- Two orders relating to choice tariff and amendments."[343]

As noted in Section III, despite Michigan's efforts at implementation and endeavors to optimize the market, decisions regarding rate caps, reductions, and management of stranded assets ultimately impeded market development. No retail electric choice structure developed, and, as also discussed in Section III, the state passed the Customer Choice and Electricity Reliability Act of 2008, as part of Public Act 286.[344] This law requires that "no more than 10 percent of an electric utility's average weather-adjusted retail sales for the preceding calendar year may take service from an alternative electric supplier at any time."[345] Public Act 286 thus places a limit on electric choice.[346] What this means in practice is that, currently, "no licensed alternative electric suppliers are marketing or enrolling residential customers."[347] Thus, the state has moved to a "hybrid model" via legislation, meaning that residential ratepayers have *de jure* access to choice but not *de facto* access.

Nevada experimented with restructuring in the late 1990s before repealing residential retail electric choice in 2001. Assembly Concurrent Resolution (ACR) 49 directed the PUCN "to study deregulation" in 1995.[348] In July 1997, Assembly Bill (AB) 366 instructed the "PUCN to establish competitive market no later than December 31, 1999."[349] The PUCN opened Docket 97-8001 to study issues around retail competition in August 1997.[350] Senate Bill (SB) 438, enacted in June 1999, delayed the market open date to March 2000.[351] On April 18, 2001, AB 369 "return[ed] utilities to regulation."[352] In July of that year, "AB 661 was enacted, revising and repealing certain provisions of Nevada's restructuring law. The law allows eligible large customers, those using 1MW and above, to choose an alternative supplier for power with permission from the State [PUCN]."[ddd, 353] Even though Nevada did not implement restructuring in full, the prolonged nature of the process is evident.

Should Question 3: The Energy Choice Initiative pass in November 2018 by a majority of registered Nevada voters, the Nevada Legislature likely would have to redefine the scope of the PUCN's authority, as current law pertains to monopoly utility service. Its purview could be expanded or proscribed, though the ballot initiative requires that "...all electricity customers are afforded meaningful choices among different providers, and that economic and regulatory burdens be minimized in order to promote competition and choices in the electric energy market."[354]

What is certain is that PUCN cannot play a role in the wholesale organized market; prices are set through the auction process and coordinated by the independent system operator (ISO). Beyond that, the State likely would delineate the role of the utility regulator in statute. Our review of other states' experiences shows that utility regulators in restructured markets have set default service rates; regulated wires charges; amended competitive transition charges (CTC); established/extended rate caps, rate freezes, and rate reductions; and more.

For example, the Electric Customer Choice and Competition Act of 1999, the enabling legislation for Maryland's restructuring of its electric utility industry, delegated certain regulatory matters to the Maryland Public Service Commission (PSC). The PSC could change implementation schedules by order or settlement agreement with the incumbent utilities (at the time, Maryland had four large investor-owned utilities: Baltimore Gas and Electric Company, Delmarva Power and Light Company, Potomac Edison Company, and Potomac Electric Power Company).[355] The legislation mandated rate reductions and rate caps, but the PSC "allocated the rate reduction among generation, transmission, and distribution components of residential electric rates, thus giving a portion of the rate reduction

[ddd] This is commonly referred to as the "704B process."

to customers who chose a different generation supplier and as well as those who remained with SOS {Standard Offer Service].”[356] The PSC also approved alternative rate requirements for distribution service and SOS.[357] Amongst other responsibilities with which it was entrusted, not all of which are enumerated here, the PSC also approved transition plans for the treatment of transition (i.e., stranded) costs or benefits.[358]

Insofar as the role of the PUCN under retail electric choice remains uncertain, so too does that of NV Energy. The ballot initiative does not specify that investor-owned utilities be restructured but rather permits “…every person, business, association of persons or businesses, state agency, political subdivision of the State of Nevada, or any other entity in Nevada…the right to choose the provider of its electric utility service.”[359] This language affords the Nevada Legislature broad discretion over the limits of NV Energy’s operations, should it wish to remain in a restructured market in any capacity. And it raises questions regarding current law: What must be left intact? Which statutes would require revision? How would the established regulatory framework interact with the incumbent utility, when its operations are undetermined but likely to be circumscribed? These matters are interlocking, and decisions cast in any one regard could produce any number of variable outcomes. As examples, we discuss the Provider of Last Resort (POLR) and net metering.

There are two models for the POLR: Texas and all other restructured states. As previously mentioned, Texas established a “price to beat” that acted as a ceiling and a floor. For the first five years of transition, Texans in restructured areas were switched automatically to retailers affiliated with the traditional utilities, which charged the regulated “price to beat”; however, ratepayers could switch to competitive suppliers, which were permitted to provide lower rates.[360] Today, all Texans in restructured areas must select a competitive supplier. As such, there is no Standard Offer Service (SOS) option, that is, service for customers who do not choose a generation supplier. (SOS also may be referred to as basic service in other restructured states, or, less frequently, default service, as this term typically is associated with the transitional model in Texas.) However, if a retail supplier cannot continue service, Texans receive temporary service from a Public Utility Commission of Texas-designated POLR.[361]

In the remaining restructured states, competitive supply take-up is not mandatory. Customers can opt to switch to a retail electric supplier, or they may remain with the incumbent utility through its SOS.

The two models differ considerably, though both maintain some sort of role for the incumbent utility in electric supply provision. Texas’s utilities only procure electric supply as a temporary, emergency measure; incumbent utilities in other states compete with retail suppliers for customers. The *Annual Baseline Assessment of Choice in Canada and the United States* (ABACCUS) report views default service as incompatible with competition, contending that it should be transitional only—or, if not, that such service should be provided by competitive suppliers, rather than incumbent utilities—so that retail electric suppliers have “headroom” to compete.[362]

Thus, the Nevada Legislature would confront a variety of decisions, such as whether to use the Texas model or that established by other states, and it would need to determine the authority for that choice. That is, would the State's enabling legislation prescribe a model, or would that determination be delegated to the PUCN? Complicating matters is that it remains unclear as to how much agency the incumbent utility would be afforded in the process. Paul Caudill, CEO of NV Energy has stated:

> For the [Governor's] Committee [on Energy Choice], we've made this public already, in presentations actually to Assemblyman [Chris] Brooks and then also the Senate, that we're ready to fully divest all generation, all power purchase agreements, and, to get to your point about...what I'll call the Provider of Last Resort or Standard Offer Service or default service, we have no interest in performing that function, so our role right now is to kind of think about transitioning to a wires-only company, if that's what the State wants us to do....[363]

Regardless of the model that might be selected by the State, NV Energy thus has asserted that it does not wish to provide some sort of default service. The Nevada Legislature and/or the PUCN would need to identify an alternative supplier, be it for transitional or emergency service or as a more permanent option for ratepayers. We note the following: (1) it is not outside the realm of possibility that the State could make provision of default service, however defined, a condition of NV Energy's remaining in the market as the wires company; and (2) whichever entity provides default service technically plays a role in electricity supply, even in as a limited a case as Texas.

This brings us to our second example, net metering, which speaks to the questions of existing law, the obligations of the incumbent utility, and the PUCN's authority under retail electric choice. Net metering is a process in which a purchased or leased solar system (typically, rooftop solar) may produce excess energy, and in such cases, if what is produced exceeds more than what is used in a billing period, the excess energy is "pushed back onto the grid and used by other electricity customers"; in the next billing cycle in which consumption is greater than production, these customers receive a credit on their electricity bills.[364] According to the Solar Energy Industries Association (SEIA), a national trade association of the U.S. solar energy industry, 425,022 homes in Nevada are powered by solar (27,308 installations; and 2,607.18 mW of installed solar).[365]

In the 79th (2017) Legislative Session, Assembly Bill (AB) 405 was enacted, which established a rate structure for net metering customers, effective June 15, 2017.[366] The PUCN can approve draft orders on rates and rules for net metering customers.[367] Several industry experts shared with the Guinn Center their concern that passage of Question 3: The Energy Choice Initiative, effectively would nullify the provisions of AB 405.[368] One industry expert expressed the logic, as follows:

> Net metering customers will not get the rate from NV Energy for excess energy. And NV Energy will not buy it back anymore, as it will no longer remain in the supply business. But who will? Legislators will need to figure it out. Will the State take on the financial burden of buying that energy? What about folks coming in to buy energy? Net metering customers' understanding right now is an expectation for the recovery of costs paid for 20 years at certain rates.[369]

It is not clear that approval of Question 3: The Energy Choice Initiative, in fact, would invalidate preexisting statutory authority, formally. But, to the extent that the ballot initiative requires competition and choices, it would seem to imply that NV Energy not remain an electric supplier—this is why divestiture has been presumed, as well. If NV does not supply generation, then, by definition, it is not a supplier than can provide retail rates. Therefore, there would be no entity in the market with the ability to provide the net metering service. In the absence of further clarification, the right to energy choice seems incompatible with the rights guaranteed to net metering customers.

This raises the same questions as the POLR and is linked inextricably to the default service issue. To the former: (1) What could the State require, and to what extent would the PUCN be delegated authority to address these issues?; and (2) would NV Energy (or some other entity) be willing to accept the net metering provisions if it wants to provide wires service?

The discussion of default service suggests one caveat to the idea that the elimination of the monopoly service provider from the electricity supply market means that no entity would exist to ensure that the rights of net metering customers are upheld. While it may be true that NV Energy might not be that company, either the Nevada Legislature, through enabling legislation, or the PUCN, through regulatory order (if delegated that responsibility by the Nevada Legislature), could enforce net metering rules on some entity that wants to participate in the market or enter it anew.[eee] This sort of designation may be true for the default service provider, as well, and since that entity would remain in the generation business, either as the POLR or via provision of an SOS option, one possibility might be to assign it net metering obligations, pursuant to AB 405. Ohio offers an example of a restructured state in which its law requires the wires companies to provide net metering to customers who generate several types of renewable energy; the Public Utilities Commission of Ohio issues related rulings and provides oversight.[370]

Thus, the implementation challenges raise another—and perhaps more pressing—issue: Question 3: The Energy Choice Initiative seeks to restructure Nevada's electricity market through an amendment to the *Nevada Constitution*. In contrast, all other states, with the exception of New York, which restructured its electricity market through a regulatory order issued by its Public Service Commission, did so through legislation.[371]

The ballot initiative before voters (Question 3) specifically would enshrine electric utility service provision as a right in the *Nevada Constitution*. It states that, "…every person, business, association of persons or businesses, state agency, political subdivision of the State of Nevada, or any other entity in Nevada has the right to choose the provider of its electric utility service, including, but not limited to, selecting providers from a competitive retail electric market, or by producing electricity for themselves or in association with others, and shall not be forced to purchase energy from one provider."[372] There is precedent, however, for state constitutions to incorporate rights traditionally not deemed as such, including provisions for poverty, housing, shelter, and nutrition.[373] In addition, "Many state constitutions also include declarations that set out as inalienable the right to seek and/or obtain safety and the right to pursue and/or obtain happiness."[374] Whether there is a right to electric utility service may be a matter for legal scholars to contemplate, admittedly.

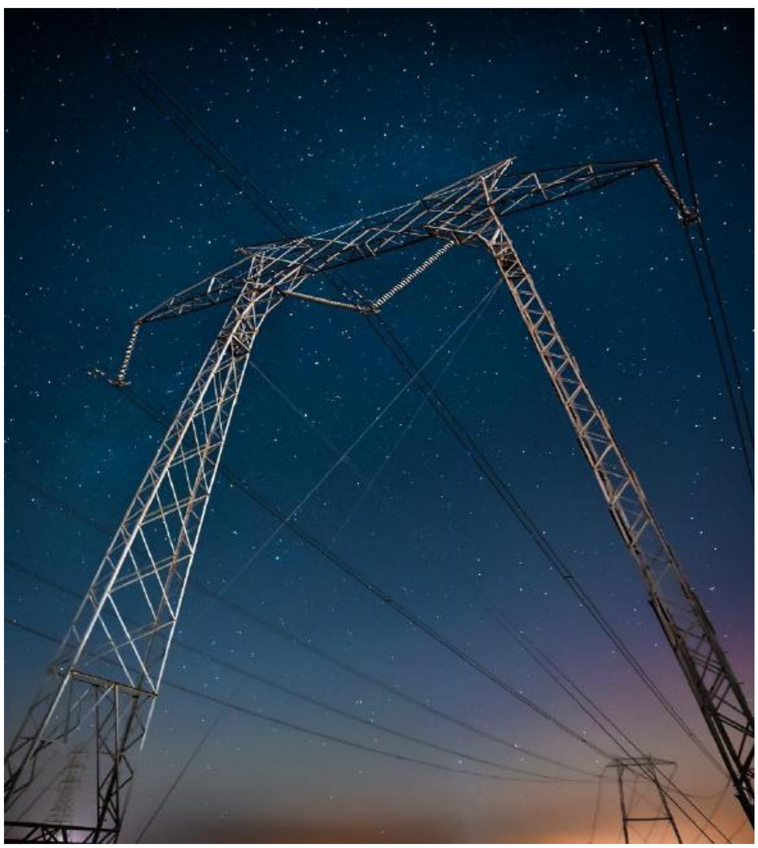
Currently, though, "the Nevada Legislature has passed laws which allow investor-owned utilities in Nevada to be monopolies."[375] This means that there is statutory authority granting the utility

[eee] NV Energy might not be the entity in question, perhaps through the possible nullification of AB 405, or a potential decision not to remain the wires company and accept the conditions that may come with it (both of which are unknown at this time), amongst others.

exclusive franchise over a designated service territory.[376] What this suggests is that, historically, electric utility service has been understood as a policy and/or regulatory matter in Nevada, not a constitutional one.[377]

However, using the *Nevada Constitution* as a regulatory tool forces the Nevada Legislature to proceed with restructuring, even if legislators find that their constituents would not benefit. As noted earlier, many states were unable to anticipate all the issues they eventually would confront until they began to implement the law or until well after. If legislators find that restructuring would be infeasible, the constitutional imperative would take precedence—that is, it would supersede the delegated authority with which legislators are entrusted—leaving the Nevada Legislature without recourse to take more time to vet the issue. Moreover, this is a five-year implementation process, and the Nevada Legislature would have to work on this over three legislative sessions.

And should Nevadans become less sanguine about the prospects of restructuring, they would have to repeat the process outlined in the Introduction of this report, as repeal of a constitutional amendment would require another constitutional amendment. Specifically, this would entail circulation of a petition to obtain the requisite number of signatures to appear on the ballot and then passage in two successive elections.[fff]



[fff] If Question 3 were to pass in November 2018, and in the intervening years, the people determined that they did not wish to see the electricity market restructured, after all, the earliest that a repeal measure could appear on the ballot is November 2020; it could not be repealed in full until November 2022. Thus, the uncertainty around market restructuring exposes Nevadans to risk that would be constitutionally enforced.

V. Conclusion

For years, most people understood electricity through their interactions with the utility, whether that meant reliability of service or billing questions. Restructuring has altered that relationship for residential customers in 15 states. They can select a competitive supplier—or, in the case of Texas, must select a competitive supplier—while the incumbent utility provides the wires (grid) service. Question 3: The Energy Choice Initiative (ECI) presents that decision to Nevadans through an initiative petition that will be placed on the ballot in November 2018. Should Nevada restructure its electricity market and permit retail choice access for residential customers?

Given the messaging on both sides of the debate, this report has endeavored to clarify the assertions promulgated by supporters and opponents. In compiling our report, the Guinn Center conducted an extensive review of federal energy data and more than two dozen interviews with energy industry experts (on both sides of the issue) around the country, and reviewed research documenting the experiences of other states that restructured their electricity markets (and adopted "energy choice"). Upon the completion of this review the report has reached certain findings.

This report has found that some people in restructured states have enjoyed the benefits of retail electric choice, while others have confronted unfavorable outcomes. The impact of restructuring turns largely on market design and policy decisions rendered before and during the implementation phase. But even those states that proceeded with caution and careful consideration were not invulnerable to unintended consequences.

This report also finds that research indicates that restructuring has no bearing on the increased integration of renewables onto the grid, nor does it hinder progress toward Nevada's clean energy future. While the implementation of Question 3, if it passes, could require minimum standards for inclusion of renewables for eligible sellers in a wholesale electricity market, Question 3 does not by its plain language require integration of renewables into the grid.

Many Nevadans likely want to know what will happen with their electricity rates. This report finds that this question cannot be answered with any certainty, because there are too many variables that interact with one another even to produce a reasonable forecast or projection of what may happen to rates under restructuring in Nevada. We do know, however, that residential electricity rates in a restructured wholesale market will be more directly dependent upon the underlying prices of different forms of power generation, such as natural gas, solar and geothermal, than under the current monopolistic utility structure. Thus, for example, for states like Nevada that currently depend heavily on natural gas, their electricity rates in the wholesale market will vary more (up or down) with natural gas prices.

The opportunity to restructure its electricity market presents Nevadans with a different option and potential for its energy future, but the price of that decision is uncertainty. Given the evidence, we cannot argue conclusively that energy choice (Question 3) is either "good" or "bad" for Nevada. In other states that adopted energy choice and restructured their electricity markets, decision-makers subsequently had to intervene to stabilize markets and protect consumers, facilitate competition, and establish new or revise existing regulatory frameworks. In other words, the experiences of other states suggest that restructuring is a complex and prolonged process that will take time, and only after retail electric choice is realized fully would Nevadans be able to determine if restructuring was the “right" path. Voters and decision-makers in the Silver State will have to identify and weigh their priorities in assessing issues of cost (and price variability), consumer choice (and protection), and sources of electricity generation.

Appendix A. The Market for Electricity: Explanations from Various Sources

Energy Manager Today (News and Best Practices for Commercial & Industrial Energy Managers)

"The auction process is designed to match electricity supply to demand at the lowest possible price point. The ISO, which oversees the process, predicts the hourly demand. Each generator offers a specific amount of generation capacity (supply) into the market at specific prices. In theory, the offer prices are based on the cost to operate the facility.

Once the offers are made, the ISO sorts them in ascending order to determine how much supply is available at different price points. It then selects the 'winning' bids – the lowest-priced combination of offers required to meet demand – which will be dispatched at the hour dictated by the auction. The clearing price is set based on the marginal (most expensive) unit of generation required to meet demand."[378]

PJM Learning Center (PJM is an ISO [RTO])

"The wholesale market begins with generators, which, after securing the necessary approval, connect to the grid and generate electricity. The electricity produced by generators is bought by an entity that will often, in turn, resell that power to meet end-user demand. These resale entities will generally buy electricity through markets or through contracts between individual buyers or sellers....

The price for wholesale electricity can be predetermined by a buyer and seller through a bilateral contract (a contract in which a mutual agreement has been made between the parties) or it can be set by organized wholesale markets. The clearing price for electricity in these wholesale markets is determined by an auction in which generation resources offer in a price at which they can supply a specific number of megawatt-hours of power....

If a resource submits a successful bid and will therefore be contributing its generation to meet demand, it is said to 'clear' the market. The cheapest resource will 'clear' the market first, followed by the next cheapest option and so forth until demand is met. When supply matches demand, the market is 'cleared,' and the price of the last resource to offer in (plus other market operation charges) becomes the wholesale price of power.

After electricity is bought by resell or 'supply' entities in the wholesale market, it can be sold to end-users in the retail market....

Many consumers have options for purchasing electricity. They can choose from their local utility or a number of competitive retailers to find the service that best fits their needs. These resellers (retail electricity providers) purchase electricity though wholesale electricity markets before they resell it to consumers...."[379]

Bates White (Economic Consulting Firm)

ISOs "..determine which sources of electricity will be used to meet demand, selecting or 'dispatching' the cheapest sources available at any time. Low-cost 'baseload' plants are dispatched first, followed by higher-cost resources, according to need, and independent of whether the resources are used to serve local or more distant needs. This is called 'economic dispatch.'

When the system uses economic dispatch, the cost of the very last generating plant needed to supply power in a given hour sets the system cost.

Where there is vigorous wholesale market competition, such as in PJM, centralized dispatch is no longer determined by a system operator using estimated incremental costs for each generating plant. Instead, PJM uses a bid-based system, in which individual generators submit their own price bids every day to the system operator to meet the expected customer demand for the following day. Once the system operator has all of the bids, he selects those generators whose bids are lowest and tells generators who are not selected that they will not be needed.

Bid-based energy markets begin with generators submitting their bids to the system operator in the day-ahead (DA) market. As its name implies, the day-ahead market takes place the day before the actual operating day. The DA market is a financial market, rather than a physical one. Essentially, the DA market is like a commodities futures market that allows buyers and sellers to hedge their transactions. Selling generation in the DA market, like selling orange juice futures, doesn't mean the seller is committed to physically delivering their product. Instead, generators whose bids in the DA market are accepted are bound into a financial obligation. A generator that cannot physically provide the power bid the previous day must obtain that power in the real-time (RT) market, which is a 'physical' spot market. It is in the real-time market that generators provide the electricity needed to keep the lights on.

In practice, bids will in fact tend to approximate actual marginal costs–a generation owner stands to lose money by bidding above marginal cost and not being selected, or by bidding below marginal cost, being selected, and then being unable to recoup the costs to produce electricity….Since the market-clearing price will always be positive, owners of baseload plants know they will still be paid for their generation, even though in many offpeak hours when electric demand is low, the market prices will be below their plants' average costs."[380]

Further Explication on Bates White and Economic Dispatch (William W. Hogan, Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University)

"The Bates-White statement is correct, but only If you are careful about the precise definition of every word and include demand side bidding.

…the basics, for the canonical convex case:

…you see the standard supply and demand construction, ignoring the effects of different locations in a grid. The…supply curve would be the generator offers. At every moment the intersection of supply and demand defines the standard market clearing price charged to all loads and paid to all generators. Economic dispatch takes the cheapest generators first.

Note that at the highest period the intersection of supply and demand is above the variable cost of the most expensive generator producing at that time. This is the effect of scarcity prices to account for the limits on the capacity of lower cost generation.

…[where] the model is closer to the real situation with a transmission system…the supply offers and demand bids in effect present supply and demand curves at different locations. The theory of locational pricing extends the ideas…by incorporating transmission constraints and the equilibrium conditions across the whole grid. Now there are different market-clearing prices at each location. Again, generation is paid and load is charged according to their respective locational prices. The basic intuition…extends to this equilibrium solution[.]

Note that at the locational market clearing prices, only those generators actually producing get paid the locational energy prices, and no generator whose variable cost is greater than the respective locational price is producing energy.

With economic dispatch, the locational marginal prices are the only prices that support the solution in the sense that nobody has an incentive to deviate from the economic dispatch. This is also the only pricing mechanism that allows for open access and non-discrimination. This is a critical feature that is often overlooked or wished away.

In these standard examples and interpretations, there are no commitment costs or other non-convexities. This gets into extended locational marginal prices, which is a more advanced topic."[381]

Appendix B. Annual Average Retail Price of Electricity (¢/kWh), 2017[382]

	Residential	Commercial	Industrial	All Sectors
Alabama	12.61	11.62	6.23	9.89
Alaska	21.57	19.46	16.59	19.52
Arizona	12.50	10.58	6.45	10.71
Arkansas	10.22	8.44	5.93	8.18
California	18.24	15.89	12.87	16.14
Colorado	12.13	9.95	7.29	9.94
Connecticut	20.31	16.10	13.31	17.62
Delaware	13.44	9.95	7.70	10.99
District of Columbia	12.93	11.68	8.25	11.81
Florida	11.85	9.61	7.90	10.65
Georgia	11.80	9.98	5.82	9.75
Hawaii	29.50	26.82	22.92	26.07
Idaho	10.11	8.02	6.69	8.30
Illinois	12.70	8.87	6.37	9.33
Indiana	11.95	10.30	7.39	9.61
Iowa	12.60	9.62	6.31	8.92
Kansas	13.27	10.49	7.49	10.58
Kentucky	10.64	9.70	5.58	8.44
Louisiana	9.51	8.91	5.42	7.75
Maine	15.96	12.14	9.09	12.94
Maryland	13.99	10.76	8.32	12.00
Massachusetts	18.92	14.88	13.48	16.14
Michigan	15.47	11.02	7.32	11.39
Minnesota	13.19	10.58	7.73	10.53
Mississippi	11.19	10.30	6.12	9.19
Missouri	11.27	9.32	7.06	9.83
Montana	11.11	10.20	5.15	9.02
Nebraska	10.98	8.98	7.66	9.16
Nevada	**12.00**	**7.98**	**6.13**	**8.76**
New Hampshire	19.22	14.75	12.33	16.16
New Jersey	15.69	12.31	10.16	13.38
New Mexico	12.92	10.27	6.01	9.64
New York	18.04	14.76	5.94	14.78
North Carolina	11.12	8.56	6.11	9.15
North Dakota	10.40	9.18	8.62	9.26
Ohio	12.37	9.97	6.69	9.71
Oklahoma	10.48	7.97	5.27	8.12
Oregon	10.71	8.88	6.19	8.98
Pennsylvania	14.33	8.99	6.75	10.16
Rhode Island	18.30	15.24	14.58	16.44
South Carolina	12.78	10.49	6.09	9.83
South Dakota	11.68	9.58	7.80	9.98
Tennessee	10.65	10.50	6.03	9.54
Texas	11.18	8.31	5.49	8.55
Utah	11.04	8.74	6.12	8.66
Vermont	17.65	14.61	10.08	14.57
Virginia	11.67	8.07	6.67	9.28
Washington	9.60	8.51	4.66	7.94
West Virginia	11.62	9.57	6.64	9.00
Wisconsin	14.68	11.08	7.79	11.05
Wyoming	11.41	9.75	6.91	8.29
United States	12.90	10.68	6.91	10.54

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About the Kenny C. Guinn Center for Policy Priorities

The Kenny C. Guinn Center for Policy Priorities is a 501(c)(3) nonprofit, bipartisan, independent policy institute focused on providing fact-based, relevant, and well-reasoned analysis of critical policy issues facing Nevada and the Intermountain West. The Guinn Center engages policy-makers, experts, and the public with innovative, data-driven research and analysis to advance policy solutions, inform the public debate, and expand public engagement.

Contact information:
Kenny Guinn Center for Policy Priorities
3281 S. Highland Drive, Suite 810
Las Vegas, Nevada 89109
Phone: (702) 916-0746
Email: info@guinncenter.org
Website: www.guinncenter.org

Nancy E. Brune, Ph.D., Executive Director
Email: nbrune@guinncenter.org

Suzanne Bierman, J.D., M.P.H., Director of Health Policy
Email: sbierman@guinncenter.org

Meredith A. Levine, M.A., M.Phil., Director of Economic Policy
Email: mlevine@guinncenter.org

Tony S. Foresta, M.A., Research Fellow
Email: tforesta@guinncenter.org

Jules Schoolmeester, Director of Outreach & Public Engagement
Email: jschoolmeester@guinncenter.org

Lorena Rodriguez, Chief Organizer & Bilingual Policy Analyst
Email: lrodriguez@guinncenter.org

center for
ENERGY STUDIES
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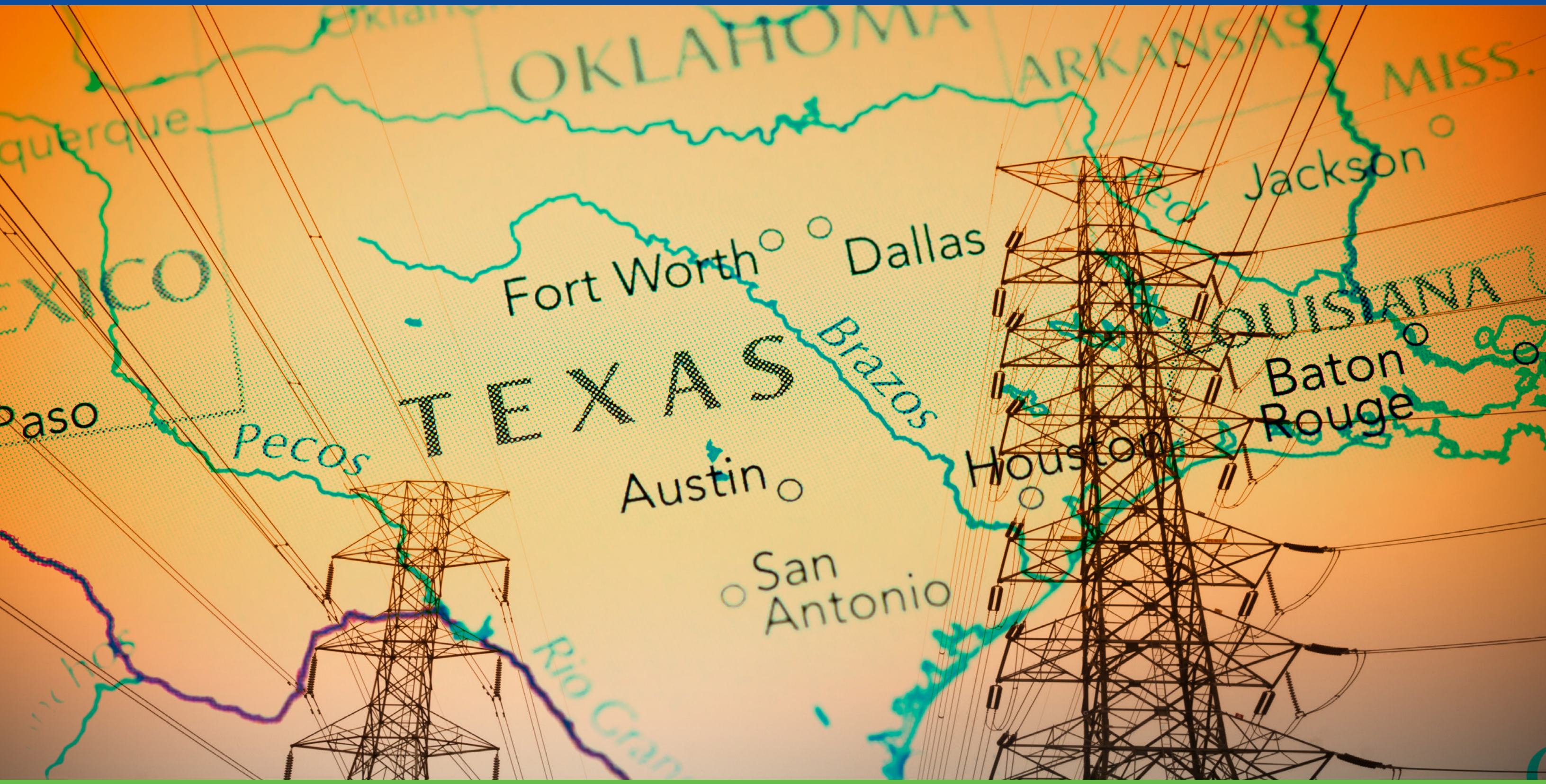

ELECTRICITY REFORM AND RETAIL PRICING IN TEXAS

Peter R. Hartley, Ph.D.
George and Cynthia Mitchel Professor of Economics, Department of Economics, Rice University; Faculty Scholar, Center for Energy Studies, Baker Institute

Kenneth B. Medlock III, Ph.D.
James A. Baker, III, and Susan G. Baker Fellow in Energy and Resource Economics and Senior Director, Center for Energy Studies, Baker Institute

Olivera Jankovska
Nonresident Scholar, Center for Energy Studies, Baker Institute

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Peter R. Hartley, Ph.D.
Kenneth B. Medlock III, Ph.D.
Olivera Jankovska
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Abstract

Electricity market reforms have pursued two main goals, both aimed at increasing economic efficiency. The first is to make prices more reflective of costs so that consumers can make more efficient decisions about where and when to consume electricity. The second goal is to ensure that suppliers minimize the costs of supply. How successful has electricity market reform in Texas been with regard to achieving these goals? We focus on one aspect of this overall set of desired outcomes, namely whether movements in retail prices reflect wholesale market prices and whether reform has delivered cost reductions in the delivery of energy services by retailers. We find clear evidence that retail prices in competitive market areas better reflect wholesale prices and have moved favorably for consumers relative to wholesale prices. The same is not necessarily true for consumers in non-competitive market areas. This suggests that competitive retail markets have delivered cost reductions consistent with electricity service providers reducing their marginal costs. The effort that Texas undertook over a decade ago to introduce competition into the retail electricity supply thus appears to be yielding the benefits to consumers that were intended in competitive areas. Consumers in less competitive areas do not appear to have benefited as much.

I. Introduction

Electricity markets in the United States have generally exhibited one of two types of market structures—often characterized as "regulated" versus "deregulated"—or a combination thereof.[1] The first extreme, a regulated vertically integrated utility, is the older, more traditional form of load-serving entity. In the past two decades, however, market reform has, to varying extents, unbundled the vertically integrated paradigm and facilitated entry by new firms, resulting in competition at the wholesale or retail level, or both. The more competitive structures can also retain varying degrees of price and service regulation, and different mechanisms for determining market prices. The introduction of reforms has varied regionally and over time, but the general tendency in the US since the 1990s has been a slow movement toward deregulated, competitive markets. In fact, according to the US Energy Information Administration (EIA), by 2015 over 20% of total US electricity sales came from retail power marketers or retail energy providers.

The Texas electricity market featured vertically integrated utilities until the passage of Senate Bill 7 in 1999, which allowed competition in the market.[2] Utilities were restructured or "unbundled" into retail energy providers, generators, and distribution and transmission

[1] The characterization of electricity markets as "deregulated" is an oversimplification. Electricity market reform generally increases the number of competing firms at the wholesale and retail levels by splitting formerly vertically integrated firms, and alters the rules of the market in order to facilitate entry and competition at the wholesale and retail levels. Thus, the change might be better characterized as a change in the market structure and regulatory apparatus away from the traditional vertically integrated regulated monopoly model of the past rather than an elimination of regulation altogether.

[2] Zarnikau (2005), Adib and Zarnikau (2006), and Zarnikau and Whitworth (2006) provide detailed overviews of the Texas electricity reform.

utility companies before consumer choice commenced 15 years ago, in January 2002.[3] In the five years that followed, transitory provisions such as mandated price caps or "price-to-beat" were established to incentivize market entry.

Today, "the ERCOT market is generally considered to be the most successful of the restructured electricity markets in North America" (Zarnikau 2011), with more retail competition than any other market in Canada and the US (DEFG 2015). Moreover, the Texas market is remarkable among deregulated markets for its customer participation. According to the 2017 Public Utility Commission of Texas draft report "Scope of Competition in Electric Markets in Texas," as of March 2016, 92% of all customers have exercised their right to choose an electricity provider (PUC 2017). The success is also evidenced by the fact that about 75% of all electricity sold in Texas is to retail choice consumers (ERCOT 2016).

The Texas experience is not universally accepted as a success. Notably, a recent study commissioned by the Texas Coalition for Affordable Power (TCAP 2016) claims that electricity deregulation in Texas has not delivered the intended outcome. In particular, the study notes among its major findings that Texans paid average residential rates that were 6.4% below the national average in the 10 years prior to deregulation but 8.5% higher in the 10 years following deregulation. The study also asserts that the "price-to-beat" mechanism failed, highlights the role of natural gas prices as a determining feature of electricity prices, and points to higher transmission and distribution costs as factors that have contributed to higher rates in Texas.

In this study, we find that residential rates in competitive and non-competitive areas of Texas have behaved in a manner that is consistent with economic theory. More specifically, residential rates in competitive areas are highly reflective of wholesale rates, which suggests that electricity providers are minimizing costs in meeting market demands. By contrast, residential rates in non-competitive areas do not generally reflect wholesale rates. Furthermore, we find a shrinking gap between residential rates and wholesale rates in competitive areas, which is consistent with improvements in firm and market efficiency. This also has not generally been the case in non-competitive areas.

Importantly, we also find that residential rates in areas with regional cooperatives tend to behave more similarly to those in competitive market areas. A possible explanation is that such cooperatives still must effectively compete with outside entities for market access. We elaborate more on this below, but the implication is that the introduction of market competition has spillover effects on some less competitive market areas.

We have also examined site-specific load and billing data for several large commercial consumers of electricity. This provides a more complete picture of the behavior of electricity rates in the state of Texas across competitive and non-competitive areas since market reforms began. The data reveal that commercial electricity consumers in non-

[3] Intelometry (2008) provides a detailed description of the utility unbundling and name history.

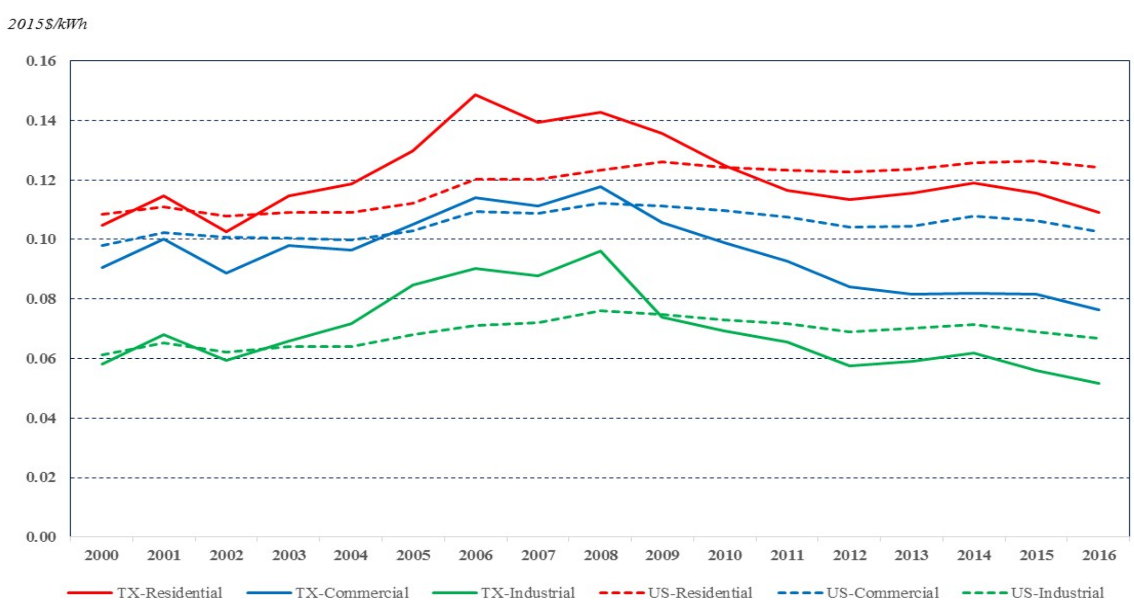
competitive areas generally pay higher rates than those in competitive areas. Commercial customers in non-competitive areas may thus be cross-subsidizing residential customers. Since commercial customers tend to have a lower price elasticity of demand, this may indicate that local load-serving entities in non-competitive areas are engaging in more price discrimination. However, if the cross-subsidies become large relative to the costs of onsite generation, such as the falling cost of (subsidized) solar power, commercial customers may install their own generating capabilities. In that case, residential rates may be forced to adjust upward so that the utility can cover its costs.

In Section II we provide background information on the Texas electricity market and reforms and discuss some relevant literature. Section III discusses the data and methodologies used in the analysis, while Section IV presents the results and explores their implications. Section V examines commercial sector electricity rates, before we summarize our conclusions in Section VI.

II. Background and Literature

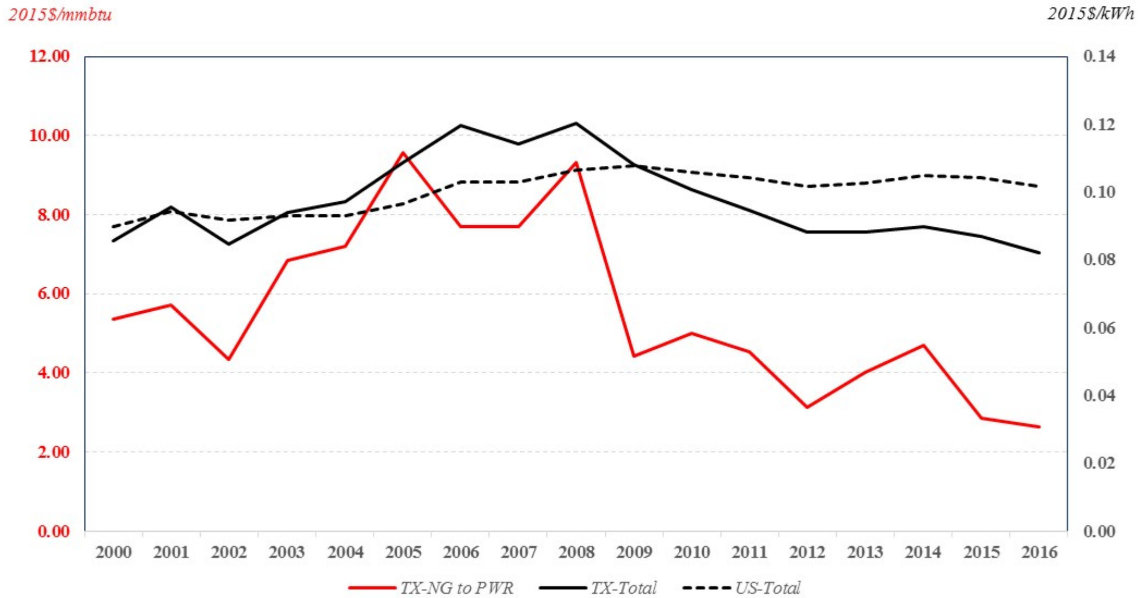
Texas consumers have historically enjoyed low retail electricity rates relative to national prices. An exception is the period from 2002 to 2010, when natural gas prices increased significantly before declining with the shale revolution. Notwithstanding volatility in energy markets, average electricity rates in Texas since 2000 across all sectors have been, on average, $0.003/kWh lower than national rates (Energy Information Administration 2016), with variation across time and across major consuming sectors (Figure 1).

Figure 1. Real US and Texas Electricity Rates by Sector, 2000-2016



Source: Energy Information Administration

Figure 2. Real Electricity Rates and Natural Gas Prices in Texas, 2000-2016



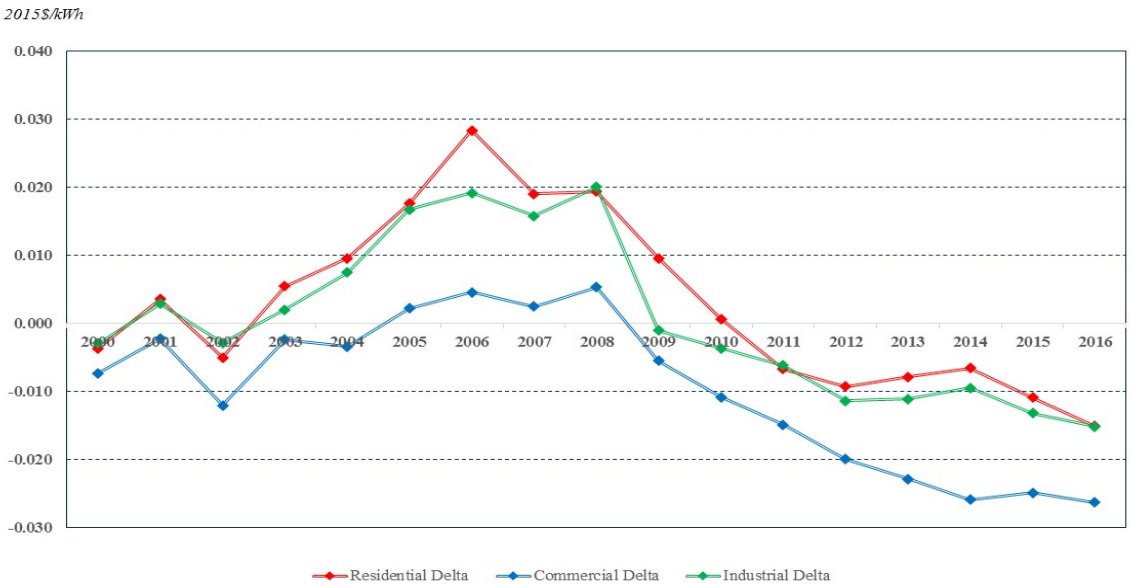
Source: Energy Information Administration

Over the same period, 2000-2016, the residential sector in Texas has averaged \$0.003/kWh above national rates, while the commercial sector has averaged \$0.010/kWh below the national average. The industrial sector average has kept virtual parity with the national rate.

Figure 2 shows that, for every sector, the temporal variation in Texas electricity prices is tied to movements in the price of natural gas. This reflects the fact that natural gas plants most often provide marginal generation in Texas. Across the nation, while there is considerable variation in regulatory regimes, there is also variation in the marginal fuel. This latter point is salient when comparing the movement of rates across time and across sectors. Indeed, when one considers the trends before and after 2008, when domestic natural gas prices peaked, simple averages comparing Texas relative to the rest of the US can be misleading. In fact, from 2009-2016 residential sector rates in Texas have averaged \$0.006/kWh below national rates, commercial sector rates have averaged \$0.019/kWh below national rates, and industrial sector rates have averaged \$0.009/kWh below national rates. Moreover, in 2016, the discount for Texas consumers dipped to \$0.015/kWh, \$0.026/kWh, and \$0.015/kWh in the residential, commercial, and industrial sectors, respectively. Thus, the discount for consumers in Texas has expanded over the last decade.

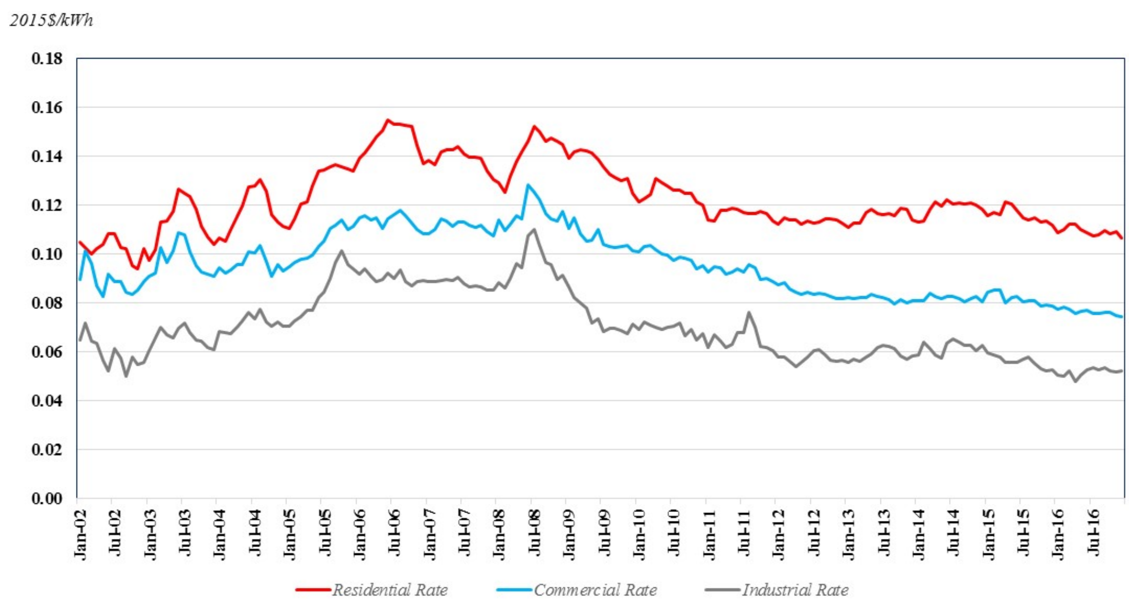
Figure 3 also shows that the differences between the US and Texas in residential and industrial electricity rates are quite different from the difference in commercial rates. Since only 20% of US electricity sales came from retail power marketers or retail energy providers as of 2015, the rate discrepancies are likely correlated to market structure. We return to this issue below.

Figure 3. Electricity Rate Differences–Texas Minus US, 2000-2016



Source: Energy Information Administration

Figure 4. Real Average Monthly Electricity Rates by Sector in Texas, Jan. 2002–Dec. 2016



Source: Energy Information Administration

Figure 4 graphs the inflation-adjusted (real) average retail rates across sectors in Texas by month. It shows that monthly rates to industrial and commercial consumers fell from the beginning of the sample to the end, while the residential rate is virtually flat. Rates generally increased from 2002 through 2006 before peaking in 2008, then declined thereafter. It is important to note electricity rates in real terms because the purchasing power of a dollar changed over the sample period for consumers and firms alike. Nominal price data examined over limited windows of time can give quite a different impression to the trends displayed in Figure 4. Such analyses have led to the observation that retail rates have increased faster in consumer choice areas compared to non-competitive market areas, with concomitant erroneous conclusions about the impact of competition in the marketplace.

There is extensive research examining the impact of deregulation and market restructuring on electricity rates. “Most studies conclude that there have been some efficiency gains [from restructuring of the electricity industry], but the subject of whether retail prices have fallen has been contentious” (Blumsack, Lave, and Apt 2008). Texas has been cited as an example with mixed post-restructuring results. As noted above, retail prices generally trended up more rapidly in competitive market areas than in non-competitive market areas from 2002 through 2006. Subsequently, retail rates tended to converge toward wholesale rates, indicating that competition was providing benefits by stimulating efficiency gains. To tease out the effects of restructuring per se, one needs to allow for other factors impacting prices in the Texas market at the same time.

Lower prices are the key benefit expected from market restructuring, but other intrinsic and extrinsic benefits are important when analyzing a policy. Previous studies have quantified some of the Texas-specific effects of market restructuring.[4] For instance, deregulation of the market resulted in increased diversity in generation mix (see, for example, Zarnikau 2011), achieved energy efficiency goals (see Zarnikau, Isser, and Martin 2015), and augmented a variety of value-added products and services (see Rai and Zarnikau 2016). Other benefits include increased consumer choice, innovative new products and services, customizable rates,[5] environmental benefits from increased renewable growth, and general market efficiency gains from competition.

A recent study conducted by the Texas Coalition for Affordable Power (TCAP 2016) shows that customers in areas exempt from deregulation have on average enjoyed lower residential rates compared to those in deregulated areas. The study also quantifies the hypothetical savings customers in deregulated areas would have enjoyed had they paid the average rates of regulated areas during the same period. Although the simplistic but objective finding that retail rates have on average been lower in regulated areas is an accurate observation, it ignores the path of prices over time and, thus, fails to identify the

[4] For an extensive list of consumer choice attributes see Goett, Hudson, and Train (2000) and for benefits and costs resulting from retail competition see Bae, et al. (2014) and Christensen Associates Energy Consulting LLC (2016).

[5] A complete list of retail energy providers, plans, and rates are available at the PUC website at www.powertochoose.com.

dynamic effects of the market reform in Texas. In particular, the study makes no attempt to assess whether rates were lower in the areas that remained regulated before the reforms were introduced, and how those rates have changed through time.

The tendency to measure the success of market restructuring in terms of retail rates may result from the tendency of policymakers and politicians to focus on the hoped-for outcomes from introducing competition as being most salient to voters. To examine this policy objective, Woo and Zarnikau (2009) develop a theoretical economic model to show that rate reduction following deregulation depends on post-reform marginal costs being below average costs. Besides pointing out post-reform failures in Ontario, California and other North American markets, the authors also note that the prerequisite assumption about the relationship between marginal and average costs has failed in Texas, specifically citing increasing natural gas prices.

Borenstein and Bushnell (2015) showed that natural gas prices have had a stronger effect on electricity rates in the US than restructuring efforts. Moreover, rates in restructured markets are dictated by marginal generation costs rather than average costs, and natural gas generators often are the marginal suppliers. By contrast, "cost-of-service" regulation tends to result in prices that reflect average costs, reducing the impact of natural gas prices and wholesale prices on retail rates. Thus, as markets continue to become more competitive, the price of electricity may be expected to move more with the natural gas price. On the other hand, other factors such as policies that internalize environmental costs and promote renewable integration may also take greater precedence over time.[6] While these factors will play out predominantly in wholesale markets, their impacts are relevant for retail price formation. Furthermore, how they manifest in retail prices will depend on market structure, in particular because wholesale prices in a competitive market reflect the marginal generation source, whatever it may be. Given the fact that natural gas is the fuel at the margin in the competitive wholesale market in Texas (ERCOT 2016), we implicitly account for natural gas price movements by including wholesale prices in the analysis.

In this study, we use 15+ years of monthly data to explore the evolving effects of market reform in Texas since January 2002. Over that time, ERCOT has progressed from a market transitioning to competition to one that is now relatively mature. Retail consumers have had ample opportunity to fully internalize the potential benefits of choice in provider. In addition, competition has expanded market depth and promoted firm-level efforts to lower costs through innovation and technology adoption.

Importantly, studies estimating post-reform electricity prices must account for price movements that resulted from multiple or phased regulatory interventions. In Texas, for example, it is possible that the periods from 2002 to 2005 and 2005 to 2007 could be impacted by market features such as a customer choice default to regulated rates and the "price-to-beat" program, respectively. Kang and Zarnikau (2009) prudently acknowledge

[6] For more information on the impact of the growth of renewables on electricity prices, please refer to Pfund and Chhabra (2015) and Tra (2016).

these effects. Specifically, by analyzing prices in Texas following the removal of the "price-to-beat" retail price caps they show that prices declined even though natural gas prices remained high during their study period.

This study uses Texas electricity price data across competitive and non-competitive market areas to focus on competitive retail electricity markets. Papers using a related approach include Joskow (2000) and Hortaçsu, et al. (2015). Similar to Borenstein and Bushnell (2015), we also examine post-reform price trends.

A note on price-taking (competitive) retail electricity providers

Consider a firm that sells electricity, q_j, to consumers in sector j at a price, p_j, and is a price-taker. It can generate its own power,[7] q_o, or purchase power in the wholesale market, q_w, to meet its customer service obligations. It will pay a price in the wholesale market given as p_w and a transfer price to its own generators given as p_o. The firm also pays for transmission and distribution, given as $\tau(q)$, where total cost is dependent on the total amount of power it sells, q. In addition, the firm must cover all other costs of operations, denoted $w(q)$. This includes items such as labor and is also positively related to total electricity sales. Finally, the firm will seek to maximize profits from all electricity sales.

Hence, we can formulate this firm's problem as

$$\max_{q_j} \sum_{j=1}^{n} p_j q_j - \left(p_w q_w + p_o q_o + \tau(q) + w(q)\right)$$

subject to

$$q = \sum_{j=1}^{n} q_j = q_w + q_o$$

$$q_j, q_w, q_o, \tau, w \geq 0$$

Noting that $q_w = \sum_{j=1}^{n} q_j - q_o$, we can find our first order necessary conditions for an interior

maximum as

$$\frac{\partial \pi}{\partial q_j} = p_j - p_w - \frac{\partial \tau}{\partial q_j} - \frac{\partial w}{\partial q_j} = 0 \quad \forall \quad j$$

[7] While many of the firms supplying retail electricity in Texas do not generate their own power—indeed separating these functions is a key part of the reform process—some vertically integrated firms remain.

and

$$\frac{\partial \pi}{\partial q_o} = -p_w + p_o = 0 .$$

Notice, this implies

$$p_j = p_w + \frac{\partial \tau}{\partial q_j} + \frac{\partial w}{\partial q_j} \quad \text{and} \quad p_w = p_o .$$

In other words, the firm will set the retail price equal to the price of power purchased in the wholesale market plus the marginal cost of operations. Moreover, it will balance delivery between its own generation sources and the wholesale market such that the price at the margin will be the same across generation sources. If the firm does not own any generation resources, then the problem simplifies to one in which $q = q_w$. Similarly, if the firm does not purchase power from the wholesale market, we have $q = q_o$.[8]

The above example illustrates that for the price-taking firm in a competitive retail market, the retail price to consumers in sector j, p_j, is a markup over the wholesale price, p_w.

The markup in the example above is given as $\frac{\partial \tau}{\partial q_j} + \frac{\partial w}{\partial q_j}$, which is a function of all distribution and operating costs the firm faces. Importantly, the firm may be able to lower its costs through reducing labor costs or transmission and distribution costs, although such investments are not explicit in this example. Such changes would lower the markup over time.

If the firm is not a price-taker or attempts to redistribute costs across consuming sectors, it may deviate from the example above. An example of this may be if the firm redistributes costs from sector j to sector k in order to satisfy a competing objective—perhaps by placing greater value on the surplus of residential consumers (and voters) than on the surplus of other customers.[9] The result would be a reduction in the markup for consumers in sector j with a compensating increase in the markup for consumers in sector k. Empirically, this would create a confounding effect for identifying the markup through time and could even mask the relevance of the wholesale price of power for retail rates in sector j.

[8] For the firms in our analysis from the state of Texas, the latter case is never true. Since our focus is the retail market, we ignore the choice of generation in this paper and assume that firms take wholesale prices as given.

[9] An example of this is seen in Hartley and Medlock (2008). They noted that competing objectives for state-owned enterprises (SOEs) interfered with a revenue-efficient outcome. Although SOEs were still assumed to be maximizing an objective, that objective included factors other than profit as a result of political influence.

In addition, in non-competitive areas where the incumbent utility holds a monopoly position, rate-making may be based on an entirely different model, such as cost-of-service. In such cases, an annual revenue target can be modeled as the sum of

- a regulated return on undepreciated capital, plus
- depreciation expenses, plus
- operating expenses such as labor, maintenance, and fuel, plus
- tax liabilities.

Price is then determined by effectively allocating revenue requirements across customers. In these cases, the vertically integrated structure of the utility can render the above model of a price-taking firm invalid because retail pricing is also dependent on the activities of the utility in the generation of electricity. By guaranteeing a rate of return on expended capital, the utility can be incentivized to expand its generation portfolio and roll its purchases from the wholesale market into its rate base. This would distort the influence of the wholesale price on the retail price, reduce the firm's incentive to improve efficiency, and encourage it to expand its rate base. If true, we would not see evidence of cost reductions over time, a point to which we return below.

III. Data and Methodology

The data used in the empirical analysis are taken from ERCOT, the Texas Public Utilities Commission, the US Bureau of Labor Statistics, the US Energy Information Administration, and the US Federal Reserve. We also have collected data under confidentiality from commercial consumers of power with facilities across the state of Texas in both non-competitive and competitive zones. All pricing and cost data are in real 2015$, using the US Consumer Price Index as a deflator.

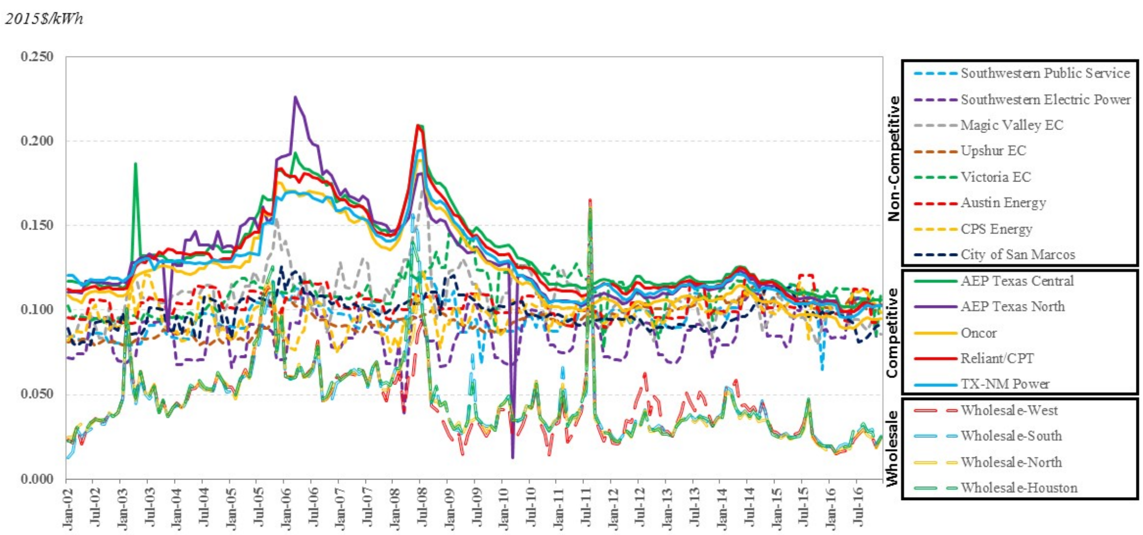
The monthly Electric Utility Bill Comparison published by the Rate Regulation Division of the Public Utility Commission of Texas (PUC 2017) gives aggregated residential electricity bill data for competitive and non-competitive areas for the years 2002 through 2016. The billing data for each residential customer grouping (at 500kWh and 1000kWh, respectively) was normalized by the load classification. This provides an effective average rate for electricity to each customer group, which is plotted in Figures 5 and 6 for the 1000kWh customer group.[10] These data are used throughout the analysis. Importantly, the rates, constructed in this manner, should be viewed as representative because the actual load in the different customer categories may not be exactly 500kWh or 1000kWh. Moreover, the billing data include non-commodity costs, such as fees for various services. Unfortunately, individual customer data is not available.

The data considered in this study are from eight non-competitive market areas—Southwestern Public Service (SWPS), Southwestern Electric Power (SWEP), Magic Valley EC, Upshur EC, Victoria EC, Austin Energy, CPS Energy, the City of San Marcos—and five

[10] Note that renormalizing the bills by a constant does not alter the conclusions of the statistical analysis.

competitive market areas—AEP Texas Central, AEP Texas South, Oncor, Reliant/ CenterPoint, and Texas-New Mexico Power. In the non-competitive market areas, SWPS and SWEP are investor-owned utilities; Magic Valley EC, Upshur EC, and Victoria EC are electricity cooperatives; and Austin Energy, CPS Energy, and the City of San Marcos are municipally-owned utilities.[11] To construct a complete time series in the competitive areas, the reported data series were merged to allow for ownership changes over time. Specifically, the data for TXU was linked with data for Oncor as of May 2007; data for Reliant was linked to data for CenterPoint; Central Power and Light was linked with AEP Texas Central; and West Texas Utilities was linked with AEP Texas North as of July 2006. The resulting time series are presented graphically in Figures 5 (monthly) and 6 (annual averages), together with four zonal wholesale price series.

Figure 5: Monthly Residential Electricity Rates (1000kWh load, 2015$) and Wholesale Electricity Prices (2015$), Jan. 2002-Dec. 2016



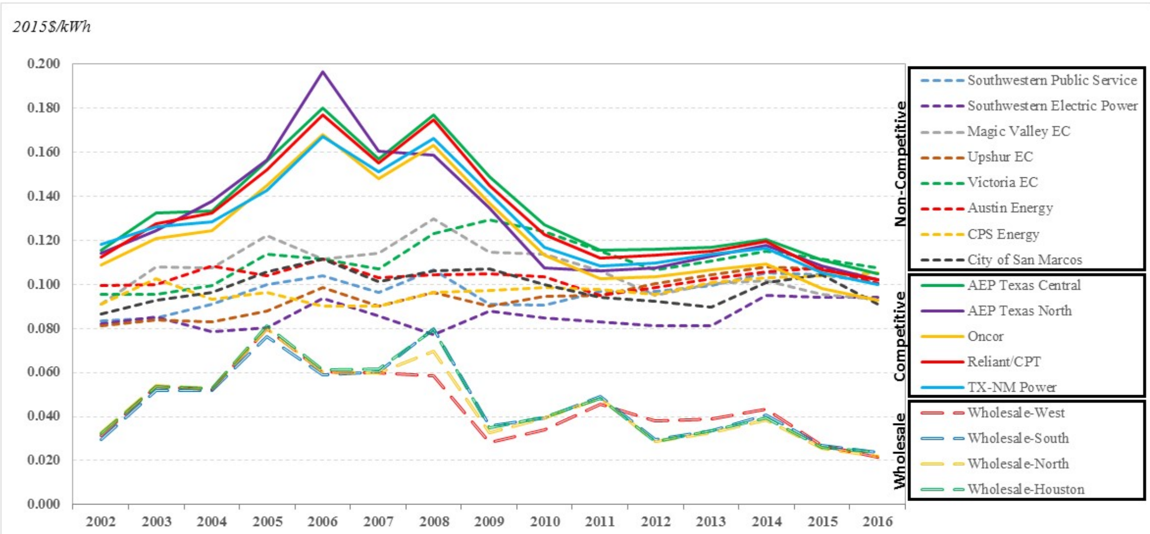
Data Sources: Nominal data collected from the Texas PUC and ERCOT and converted to real 2015$ using the US Consumer Price Index from the US Federal Reserve Database.

The ERCOT wholesale electricity price from the beginning of January 2002 through the end of November 2010 is reported as zonal 15-minute prices and obtained from the Balancing Market Prices for Energy and Resource archived datasets of the Electric Reliability Council of Texas. ERCOT wholesale prices from the beginning of December 2010 until the end of December 2016 are reported as nodal hourly day-ahead market prices and are obtained from the Day-Ahead Market Information portal of the Electric

[11] While there are more non-competitive market areas than those included in this analysis, the time series data are incomplete. Notably, Pedernales EC, one of the largest electricity cooperatives in the nation, is not included in this analysis for this reason. We also opted to use data for those areas that lie within ERCOT so that the wholesale prices remain relevant for the retail pricing in each region.

Reliability Council of Texas. The two wholesale price series are merged to create the time series of zonal wholesale prices used in the analysis.

Figure 6. Annual Residential Electricity Rates (1000kWh load, 2015$) and Wholesale Electricity Prices (2015$), 2002-2016*



Data Sources: Nominal data collected from the Texas PUC and ERCOT and converted to real 2015$ using the US Consumer Price Index from the US Federal Reserve Database.

*Note the data are annual averages so do not depict the seasonality in rates in some non-competitive areas that is apparent in Figure 5.

The annual data in Figure 6 are presented for illustrative purposes only, but they do reveal some insights obtained from the statistical analysis of the monthly data below. To begin, the annual data indicate residential prices closely track wholesale prices in the competitive market areas, but generally do not in non-competitive areas. The data also indicate that residential rates were lower in competitive areas in 2016 than in 2002, but higher in non-competitive areas. In other words, (real) prices have generally declined since 2002 in competitive areas but increased in non-competitive areas. Of course, the rates to residential customers rose significantly in competitive areas relative to non-competitive areas through 2006 before beginning to track downward after 2008. This tends to match closely the patterns observed in wholesale prices, which, as discussed above, tended to track natural gas prices.

The second observation from Figure 6 is that while the gap between retail and wholesale rates has declined over the time horizon in competitive areas, it has generally widened in non-competitive areas. This indicates competition is driving the costs of providing electricity service down in competitive areas.

To further highlight these points, Table 1 presents some summary statistics for the data considered in this study. A few things from Table 1 and Figures 5 and 6 are worth highlighting and reiterating:

- The average rate paid for electricity by residential consumers in competitive areas has been higher than that paid by residential consumers in non-competitive areas.
- In 2002, the average price paid by residential customers in competitive areas was between two and three cents higher than the rates paid in non-competitive areas. This is before market reforms and retail competition could have had a material impact on the price paid by residential customers.
- In 2016, the average price paid by residential customers in competitive areas was roughly equal, in aggregate, to the average price paid in non-competitive areas, with some competitive areas actually seeing rates below those in non-competitive areas. In fact, in all competitive areas prices declined from 2002 to 2016, but they increased in non-competitive areas over the same time period.
- Wholesale prices declined from 2002 to 2016, which is generally consistent with trends observed in natural gas markets in Texas and across the country (not pictured).
- The declines in residential prices in competitive areas from 2002 to 2016 were generally larger than the declines in wholesale prices, which is consistent with efficiency gains and associated cost reductions in the competitive market.
- The volatility of residential prices (measured by standard deviation) in competitive areas has been higher than in non-competitive areas. Moreover, price volatility in competitive areas has generally mirrored wholesale price volatility in competitive areas, but the same is not true in non-competitive areas.
- The changes in wholesale and residential prices from 2002 to 2016, and the patterns of volatility in the price series, support the notion that residential prices better reflect wholesale prices in competitive areas. This result is consistent with electricity service providers acting in a competitive market and suggests that competitive markets have delivered what was intended.

While much insight can be gleaned from the summary statistics in Table 1, it is important to evaluate the data more rigorously. Therefore, to investigate the effects of market reform on price formation at the retail residential level, we estimate a model that stipulates the retail rate for residential customers is a function of the wholesale market rate and labor cost in the electric utility industry. We also account for a variety of other effects, summarized as:

- Regular seasonal influences on residential price relative to wholesale price are captured through monthly dummy variables;
- In several utility regions dominated by electricity cooperatives, infrequent periods of extremely low rates—occurring at most six times in a single utility region during the 15-year period under consideration—were observed, perhaps due to rate promotions or other marketing mechanisms;

- Finally, the "price-to-beat" mechanism is identified with a dummy variable that takes a value of one prior to January 2007 and zero thereafter. Similarly, a time variable is also introduced for the period prior to January 2007 and the period after to account for any tendency of the retail rate to drift relative to the wholesale rate during the different periods. (Note that this also accounts for the aforementioned criticism levied in Kang and Zarnikau [2009] regarding studies that focus on the period prior to 2007.)

Table 1. Summary Statistics of Data Presented in Figure 5

		Sample Average (Jan02-Dec16)	Std Deviation (Jan02-Dec16)	2002 Average	2016 Average	Rate Change (2002-2016)
Non-Competitive	SWPS	0.0967	0.0099	0.0835	0.1007	0.0171
	SWEP	0.0856	0.0127	0.0823	0.0942	0.0119
	Magic Valley	0.1069	0.0155	0.0910	0.0933	0.0023
	Upshur	0.0948	0.0090	0.0814	0.1021	0.0208
	Victoria	0.1110	0.0117	0.0957	0.1077	0.0120
	Austin Energy	0.1032	0.0074	0.0993	0.1005	0.0013
	CPS	0.0975	0.0095	0.0910	0.1055	0.0145
	San Marcos	0.0986	0.0093	0.0867	0.0912	0.0045
Competitive	AEP-CTX	0.1341	0.0250	0.1155	0.1047	-0.0108
	AEP-NTX	0.1297	0.0288	0.1143	0.1019	-0.0124
	Oncor	0.1228	0.0243	0.1090	0.0930	-0.0161
	Reliant/CPT	0.1311	0.0247	0.1125	0.1021	-0.0104
	TX-NM	0.1275	0.0220	0.1182	0.1000	-0.0182
Wholesale	Wholesale-West	0.0449	0.0214	0.0315	0.0216	-0.0099
	Wholesale-South	0.0459	0.0232	0.0294	0.0239	-0.0055
	Wholesale-North	0.0452	0.0217	0.0329	0.0219	-0.0110
	Wholesale-Houston	0.0464	0.0234	0.0323	0.0237	-0.0086

Data Sources: Nominal data collected from the Texas PUC and ERCOT and converted to real 2015$ using the US Consumer Price Index from the US Federal Reserve Database. Calculations by authors.

We also considered accounting for the development, through 2013, of the competitive renewable energy zones' (CREZ) transmission capacity to connect wind energy resources in West Texas to load centers in Central and East Texas.[12] However, any cost impacts from the CREZ transmission infrastructure should be captured in wholesale prices. In fact, the impacts not only of transmission upgrades but also new generation capacity anywhere in ERCOT should be reflected in the wholesale electricity rates.

[12] In 2005, the Texas Legislature mandated the Texas PUC to work with ERCOT in identifying areas with the greatest wind generation potential. Those regions—totaling five across West Texas and the Panhandle—were designated as the CREZ. Subsequently, transmission plans were developed to deliver the electricity generated in those areas to load centers in Central and East Texas. The plan included about 2,400 miles of new transmission lines at a cost of about $7 billion, and was completed in 2013.

As noted above, in the competitive case where the firm is a price-taker, the retail price should be a function of the wholesale price, the cost of transmission and distribution, and any other firm-specific operating costs. As such, we estimate for each region *i* the following equation:

$$p_{t,i}^{res} = \alpha_0 + \alpha_1 p_{t-1,i}^{res} + \alpha_2 p_{t,i}^{w} + \alpha_3 w_{t,i} + \alpha_4 D^{pb} + \alpha_5 t_1 + \alpha_6 t_2 + \alpha_{7\to 17} D^{m} + \alpha_{18\to k} D_i^{pro} + \varepsilon_{t,i}.$$

The included variables (prices and wages in real terms) are defined as follows:

- $p_{t,i}^{res}$ denotes the residential electricity rate in region *i* at time *t*,
- $p_{t,i}^{w}$ denotes the wholesale electricity rate in region *i* at time *t*,
- $w_{t,i}$ denotes the labor rate in region *i* at time *t*,
- t_1 denotes the time trend from January 2002 through December 2006,
- t_2 denotes the time trend from January 2007 through December 2016,
- D^{pb} is the "price- to-beat" dummy variable that takes a value of one for all dates prior to January 2007 and zero thereafter,
- D^{m} is a vector of monthly dummy variables capturing seasonal variation, and
- D_i^{pro} is a dummy variable specific to region *i* (some regions only) that takes a value of one if very low outlier rates are observed in region *i*, perhaps due to promotions or rebates, and is zero otherwise.

Lastly, α_n are the coefficients to be estimated and $\varepsilon_{t,i}$ is an error term. We estimate the above equation for each region simultaneously using the seemingly unrelated regression (SUR) estimator, which accounts for correlation in the error terms across equations.[13]

We expect, *a priori*, that a firm acting as a price-taker will be adequately described by the above estimated equation. However, a firm in a non-competitive region will likely price its electricity sales differently as it may maximize an alternative objective function including as arguments, for example, rents on its own generation resources or political support for its politician monitors. In that case, the above estimated equation may not adequately describe the pricing behavior of firms in non-competitive areas.

[13] Ordinary least squares (OLS) on each individual equation yields consistent parameter estimates, but SUR is more efficient. We expect the error terms to be contemporaneously correlated since some explanatory variables omitted from the equation may affect many regions at the same time. SUR and OLS are equivalent when the OLS error terms are uncorrelated across equations or when each equation contains the exact same regressors.

IV. Results

Table 2 gives parameter estimates for the above model.[14] Note that Table 2 presents the results for the residential sector for consumers with a greater than 1000kWh load. The results for the 500kWh consumers are included in an appendix, but, aside from the constant term in the regression, are not very different from the results in Table 2. The difference in the estimated constant term for the two categories of customers suggests that residential consumers across the entire state face block declining rates, but the lack of difference among the other parameters suggests relative price movements are consistent across residential customer classes within each utility area.

The parameter estimates indicate strong similarities across competitive areas. In fact, estimates of the effects of wholesale prices, labor costs, the price-to-beat mechanism, observed efficiency gains, and path dependence for residential prices are all very uniform. Moreover, there appears to be little regular seasonal influence on pricing that is not already accounted for in the wholesale market.

By contrast, the results indicate that non-competitive areas vary significantly from each other and from competitive areas. In general, pricing in non-competitive areas does not tend to conform to the model of a price-taking firm presented in the previous section. Indeed, in some non-competitive areas, confounding effects mask any statistically significant relationship between retail price and wholesale price.

Regarding the influence of each variable, we begin by noting that lagged residential price was highly significant in every case. This indicates a strong path dependency in retail price formation. No other estimated parameter was highly significant in all regions.

As for wholesale price effects, only three non-competitive regions—SWPS, Magic Valley, and CPS—showed a positive statistically significant influence of the wholesale price on residential price. The parameter estimate on wholesale price for Austin Energy was statistically significant but negative, thereby indicating a major inconsistency with the paradigm of a price-taking electricity provider. Residential prices in the remaining non-competitive regions—SWEP, Upshur, Victoria, and San Marcos—yielded no statistically significant influence of wholesale price. All the competitive regions in the sample—AEP-CTX, AEP-NTX, Oncor, Reliant/CPT, and TX-NM—revealed a positive and statistically significant influence of wholesale prices on residential rates.

[14] Data diagnostic testing was also performed. Augmented Dickey Fuller tests for unit roots indicated that each of the included time series variables—real residential rates, real wholesale rates, and real labor rates— is stationary (results available upon request). We also considered pooling the data and estimating a panel, but the data fails hypothesis testing of poolability. This is discussed in the text.

Labor rates were positive and statistically significant in all the competitive regions, but in only one non-competitive region—SWEP—while being negative and significant in another—CPS. Again, this provides evidence that electricity providers in competitive market areas are behaving exactly as predicted by economic theory, while electricity providers in non-competitive market areas conform to an alternative paradigm. In short, market reform appears to be delivering what was anticipated in competitive market areas.

The impact of the "price-to-beat" mechanism was estimated as a three-pronged effect in order to capture any effects it may have had on pricing until January 2007 and thereafter. In the competitive market areas, the statistically significant parameter estimate for the dummy variable, D^{pb}, indicates that the price-to-beat mechanism reduced the residential price for a given wholesale price and labor rate. However, the positive and statistically significant slope parameter on the time trend, t_1, indicates that residential rates were generally increasing relative to wholesale rates and labor rates from January 2002 through December 2006. Given the fact that wholesale power prices were increasing over this period, the implication is that residential rates were actually increasing faster than wholesale rates during this time. However, after January 2007 the paradigm shifted in a statistically significant way. Namely, the negative and statistically significant coefficient on the time trend for January 2007 through December 2016, t_2, indicates that the residential price in competitive areas was declining relative to wholesale price and the labor rate. Given the fact that wholesale rates were declining over this period, the implication is that residential rates were falling faster. This result is consistent with electricity service providers experiencing cost reductions in dimensions other than the wholesale cost of electricity.

In the non-competitive areas, by contrast, the parameter estimates on D^{pb}, t_1, and t_2 are inconsistent across regions. For example, in SWPS, SWEP, Upshur, and San Marcos, the only statistically significant parameter estimate is on the time trends, and the parameters are positive. This indicates that residential prices in these areas generally increased relative to the wholesale price of power and labor costs throughout the time period under consideration. Since these entities own generating assets, some of this could be related to increased power purchases from the wholesale market. This could happen, for example, if the average cost of the entity's generation resources is lower than the cost of the marginal resource available in the wholesale market. As previously noted, the TCAP analysis suggested that increasing transmission costs over time could also explain the divergence between retail price and costs, although it is not clear why such an effect would be restricted to non-competitive markets. The exact explanation remains a matter of conjecture since data to test competing hypotheses was not available.

The remaining non-competitive regions—Magic Valley, Victoria, and Austin Energy—are similar to the competitive market areas with regard to the parameter estimates on D^{pb}, t_1, and t_2, with Magic Valley exhibiting the same patterns revealed by the competitive areas. Victoria and Austin Energy have patterns similar to those exhibited in competitive areas until January 2007, but neither shows statistically significant evidence of residential price reductions relative to wholesale price and labor rates after January 2007. Thus, the same type of cost reduction evidenced for competitive areas is not revealed in the analysis for Victoria and Austin Energy. Lastly, the patterns for the estimated coefficients for CPS stand in stark contrast to the other regions, again indicating a very different paradigm at work in that market area.

The seasonal patterns are most statistically relevant for residential pricing in non-competitive areas. There is statistically significant evidence that residential prices are increased relative to wholesale prices in SWPS, SWEP, Austin Energy, and CPS during the summer months. This may be due to congestion constraints internal to these market areas. However, it also could be the result of price discrimination during high demand periods. Again, the data required to assess such competing hypotheses is not currently available.

In Magic Valley, Upshur, Victoria, and San Marcos, the data indicate that residential rates actually decline relative to wholesale prices during summer months.[15] Given there is some seasonality in wholesale price—it tends to rise in high demand months—this may be the result of price smoothing in these regions. In other words, residential rates generally do not fall during summer months; rather, they do not rise as much as wholesale price in high demand periods (so they fall *relative* to wholesale price). Lastly, in competitive market areas there is little evidence of seasonal effects, with different months—ranging from April to August—revealing any statistically significant influence on residential prices in some regions. This is consistent with the result that wholesale price movements capture seasonality in competitive markets, which is simply passed on to consumers. This is reinforced by the positive statistically significant relationships estimated between wholesale and residential prices across all competitive market areas.

A caveat for the analysis herein is that residents of areas with lower population density, for example in West Texas and South Texas, may see a greater portion of their bills reflect grid maintenance costs since grid costs *per customer* would be higher. This could reduce the influence of the wholesale price on residential rates, even in competitive areas. While this does not appear to be of concern in competitive areas, it may present an issue in non-competitive areas, especially rural cooperatives.

[15] San Marcos reveals a statistically significant relationship in only one month, May, while Upshur does in two months, Victoria in four months, and Magic Valley in every month. Importantly, peak demand months during the summer time show up as statistically significant in Upshur (August) and Victoria (July, August, and September).

Table 2. Parameter Estimates (1000kWh Customers)

		Non-Competitive Regions								Competitive Regions				
Variable	**Parameter**	**SWPS**	**SWEP**	**Magic Valley**	**Upshur**	**Victoria**	**Austin Energy**	**CPS**	**San Marcos**	**AEP-CTX**	**AEP-NTX**	**Oncor**	**Reliant/CPT**	**TX-NM**
Constant	α_0	0.010878	-0.003829	0.086885	0.007998	0.056994	0.050135	0.083617	0.022316	-0.004216	-0.018176	-0.012130	-0.008362	-0.013392
	std err	0.010557	0.013368	0.019734	0.005381	0.013420	0.010509	0.014705	0.011846	0.016782	0.029089	0.008187	0.009170	0.008713
$L.p^{res}$	α_1	0.689333	0.574643	0.496620	0.871785	0.703378	0.479151	0.275170	0.837823	0.817673	0.640333	0.859447	0.853703	0.884540
	std err	0.027846	0.036824	0.039190	0.023004	0.026420	0.045629	0.049503	0.027058	0.016644	0.028641	0.012854	0.013172	0.013180
p^w	α_2	0.033535	-0.021604	0.178873	0.012773	0.006654	-0.040879	0.085994	0.013307	0.044858	0.072210	0.065241	0.060644	0.060832
	std err	0.018891	0.024426	0.031585	0.009910	0.020097	0.015916	0.022468	0.018986	0.024927	0.041491	0.011457	0.011300	0.011729
w	α_3	0.000008	0.000016	-0.000014	0.000001	-0.000010	0.000003	-0.000018	-0.000003	0.000019	0.000041	0.000017	0.000016	0.000016
	std err	0.000006	0.000007	0.000010	0.000003	0.000007	0.000005	0.000007	0.000006	0.000009	0.000016	0.000005	0.000005	0.000005
D^{pb}	α_4	-0.001950	0.000988	-0.014228	0.000343	-0.011549	-0.004110	0.011229	-0.003460	-0.011390	-0.020354	-0.006340	-0.007383	-0.004440
	std err	0.001940	0.002465	0.003847	0.000992	0.002590	0.001846	0.002617	0.002305	0.003428	0.005672	0.001827	0.002012	0.001830
t_1	α_5	0.000121	0.000084	0.000137	0.000029	0.000127	0.000148	-0.000103	0.000076	0.000194	0.000489	0.000123	0.000143	0.000076
	std err	0.000036	0.000043	0.000062	0.000019	0.000041	0.000033	0.000043	0.000040	0.000057	0.000104	0.000030	0.000033	0.000030
t_2	α_6	0.000030	0.000021	-0.000067	0.000023	-0.000013	-0.000013	0.000122	-0.000009	-0.000092	-0.000169	-0.000060	-0.000063	-0.000049
	std err	0.000013	0.000017	0.000025	0.000008	0.000016	0.000012	0.000019	0.000015	0.000023	0.000038	0.000012	0.000013	0.000012
Feb	α_7	0.000284	0.006678	-0.006330	-0.000631	-0.000982	-0.000629	0.001349	-0.001459	0.000405	-0.000214	-0.000095	0.000812	0.000007
	std err	0.001528	0.001913	0.002704	0.000766	0.001785	0.001406	0.001969	0.001702	0.002448	0.004224	0.001195	0.001333	0.001272
Mar	α_8	-0.000130	0.005011	-0.004392	-0.000481	-0.001182	-0.000861	0.005487	-0.000600	0.001916	-0.003404	-0.000093	0.000357	-0.000578
	std err	0.001525	0.001929	0.002699	0.000765	0.001784	0.001404	0.001968	0.001700	0.002445	0.004218	0.001194	0.001332	0.001271
Apr	α_9	-0.000346	0.007579	-0.004104	-0.000556	0.000854	-0.001196	0.003083	0.000016	0.005061	0.005803	0.000659	0.001266	0.000028
	std err	0.001526	0.001907	0.002701	0.000765	0.001784	0.001404	0.001990	0.001700	0.002445	0.004220	0.001194	0.001333	0.001271
May	α_{10}	-0.000526	0.020898	-0.004583	-0.000045	-0.002319	0.005911	0.004717	-0.003485	-0.001741	0.002491	0.001633	0.002327	0.001153
	std err	0.001527	0.001903	0.002710	0.000765	0.001795	0.001408	0.001988	0.001706	0.002453	0.004221	0.001194	0.001335	0.001271
Jun	α_{11}	0.008315	0.013402	-0.006124	-0.000968	-0.001648	0.008380	0.013404	-0.002598	0.002173	0.000979	0.002696	0.001455	0.000798
	std err	0.001536	0.002008	0.002730	0.000768	0.001804	0.001454	0.002013	0.001719	0.002466	0.004242	0.001197	0.001339	0.001275
Jul	α_{12}	0.002246	0.013808	-0.005328	0.000464	-0.003355	0.005380	0.012098	0.001264	0.000973	0.000004	0.000104	0.000096	-0.000882
	std err	0.001550	0.002027	0.002714	0.000769	0.001791	0.001517	0.002131	0.001710	0.002452	0.004261	0.001198	0.001336	0.001278
Aug	α_{13}	0.000994	0.011045	-0.012466	-0.001221	-0.003795	0.005635	0.005679	-0.001738	-0.001368	-0.002252	-0.001300	-0.002081	-0.002686
	std err	0.001634	0.002103	0.002762	0.000792	0.001825	0.001547	0.002178	0.001741	0.002494	0.004404	0.001217	0.001354	0.001303
Sep	α_{14}	0.003988	0.011875	-0.010947	-0.000670	-0.003556	0.004756	0.007802	-0.001450	-0.001004	-0.003360	-0.000621	-0.000924	-0.000733
	std err	0.001533	0.002001	0.002693	0.000765	0.001782	0.001505	0.002058	0.001703	0.002447	0.004227	0.001195	0.001334	0.001273
Oct	α_{15}	-0.004860	0.010049	-0.014071	-0.000153	-0.002546	-0.001524	0.001247	-0.001054	-0.000441	-0.000649	-0.000388	-0.000483	-0.000436
	std err	0.001539	0.002000	0.002780	0.000765	0.001783	0.001501	0.002049	0.001705	0.002449	0.004229	0.001195	0.001335	0.001273
Nov	α_{16}	-0.001028	-0.003472	-0.006714	-0.001555	-0.000953	-0.004504	0.000969	-0.001522	0.000936	0.000547	0.001128	0.001681	0.000604
	std err	0.001525	0.001975	0.002672	0.000756	0.001950	0.001401	0.001960	0.001709	0.002418	0.004233	0.001181	0.001318	0.001257
Dec	α_{17}	0.002624	0.004591	-0.006597	-0.000269	0.003333	-0.001530	-0.000610	0.001506	-0.000839	0.000701	-0.000224	-0.000064	-0.000855
	std err	0.001558	0.001937	0.002739	0.000778	0.001823	0.001428	0.002003	0.001733	0.002488	0.004297	0.001215	0.001356	0.001293
	R^2	0.827	0.835	0.772	0.947	0.829	0.740	0.667	0.762	0.929	0.842	0.982	0.977	0.976

Note: Parameter values in gray are not statistically significant at a 10% level. Parameter values in blue are statistically significant at the 10% level, parameter values in red are statistically significant at the 5% level, and parameter values in black are statistically significant at the 1% level. Parameter estimates for the D_i^{pro} are not reported, but are significant at the 1% level and are available upon request.

It should be noted for completeness that we also considered other model specifications. For example, we considered a pooled approach using panel data, but the data across all market areas rejects poolability. Interestingly, the competitive market areas do not reject poolability when considered as a set independent of the non-competitive areas, suggesting competition drives retail rates to reflect wholesale rates, which themselves are driven by competition and regional arbitrage. In other words, pricing in the competitive areas appears to be driven by a common data-generating process—the wholesale market—whereas pricing in the non-competitive areas does not. Indeed, tests for pooling only the data in non-competitive areas indicated the data cannot be pooled, so panel analysis is inappropriate for non-competitive market areas.

V. A Note on Commercial Electricity

As mentioned above, we have begun collecting site-specific load and billing data from commercial electricity users in Texas.[16] Aggregate data from the Texas PUC is available for commercial and industrial electricity users in non-competitive areas, but we lacked similar information for those users in competitive areas. Moreover, the data reported by the PUC is in aggregate. More detailed consumer-specific information for large electricity users is valuable because it allows a direct comparison of load and billing for a homogeneous consumer and consumer groups across different market areas. The data indicated in Figure 7 represents over 760 locations across competitive and non-competitive market areas since January 2005. We are working to expand this dataset to include additional large commercial users, but some interesting insights are already emerging.

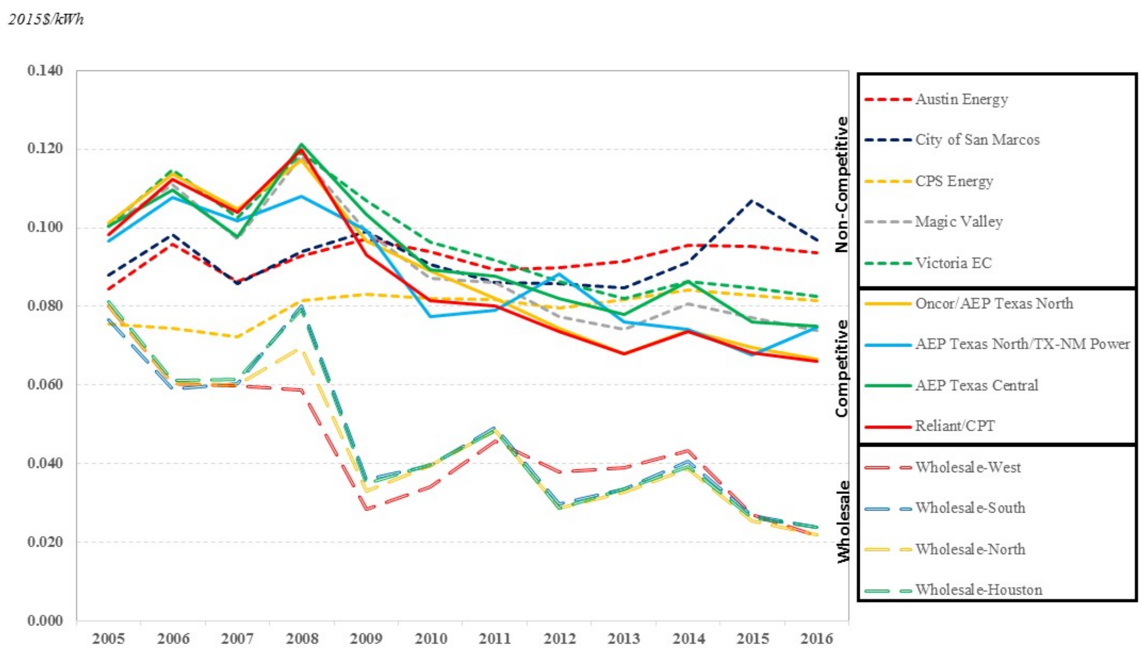
The site-specific load and billing data are collected from commercial users under a confidentiality agreement with Rice University. These data are used to calculate implied rates by location (bill divided by load), $p_{i,t}^{com}$, and then a weighted-average price for each region, $\overline{p}_{i,t}^{com}$, is calculated where the weight for each location is taken to be the share of regional load at a specific site, $\theta_{i,t}$. We then plot $\overline{p}_{i,t}^{com}$, calculated as $\overline{p}_{i,t}^{com} = \sum \theta_{i,t} p_{i,t}^{com}$, in Figure 7. For a quality check, we also compared the average price data for locations in non-competitive regions to data reported by the Texas PUC. The PUC data are area-wide regional aggregates whereas our data are for specific commercial customers in the market region, so they do not match exactly. Nevertheless, the annual averages match within half a cent in every year from 2005 through 2016.

We see in Figure 7 that there is generally less separation between the commercial rates in competitive and non-competitive market areas. However, the commercial rates in competitive market areas have followed a pattern similar to wholesale rates, while the same is not true in non-competitive areas. In fact, for the data we have collected to date,

[16] Note that the data collected is subject to a confidentiality agreement with Rice University. Hence, it cannot be distributed or shared.

commercial rates in competitive market areas have fallen relative to rates in non-competitive market areas, and are now generally lower.

Figure 7. Annual commercial electricity rates across market areas, 2005-2016*



Data sources: See text for description

*Commercial data for 2016 are incomplete, so year-to-date data is indicated. Also, note the data are annual averages so do not depict the seasonality in rates in some non-competitive areas.

Table 3 indicates some summary statistics for the data presented in Figure 7. Interestingly, we see that the commercial price in a couple of non-competitive market areas—Magic Valley and Victoria—is similar to the data for competitive market areas with regard to both volatilities and averages. This may indicate that those electricity cooperatives more closely model themselves after competitive electricity providers in an effort to attract a larger customer base.

We also see that since January 2005, the commercial rates for Austin Energy, CPS, and San Marcos have generally been less volatile than in other regions, but the rates have slightly increased through 2015 and are now higher across the board than rates in competitive market areas. Regarding competitive market areas, the general tendency for commercial customer rates has been to follow the wholesale market, which is similar to the outcome seen in the analysis of residential rates. Again, this is evidence that market reform has delivered exactly what was intended with regard to electricity pricing.

Table 3. Summary Statistics of Data Presented in Figure 7*

		Sample Average (Jan05-Dec15)	Std Deviation (Jan05-Dec15)	2005 Average	2015 Average	Rate Change (2005-2015)
Non-Competitive	Magic Valley	0.0917	0.0165	0.1005	0.0738	-0.0266
	Victoria	0.0974	0.0141	0.1003	0.0826	-0.0177
	Austin	0.0920	0.0045	0.0843	0.0935	0.0092
	CPS	0.0799	0.0070	0.0754	0.0814	0.0060
	San Marcos	0.0918	0.0090	0.0880	0.0969	0.0088
Competitive	AEP-NTX/TX-NM	0.0887	0.0181	0.0965	0.0747	-0.0218
	AEP-CTX	0.0938	0.0163	0.1003	0.0748	-0.0255
	Oncor/AEP-NTX	0.0900	0.0187	0.1013	0.0666	-0.0347
	Reliant/CPT	0.0884	0.0194	0.0981	0.0660	-0.0321
Wholesale	Wholesale-West	0.0467	0.0226	0.0801	0.0269	-0.0531
	Wholesale-South	0.0483	0.0249	0.0765	0.0269	-0.0496
	Wholesale-North	0.0469	0.0231	0.0800	0.0255	-0.0545
	Wholesale-Houston	0.0485	0.0252	0.0811	0.0262	-0.0549

Data sources: See text.

*Commercial data for 2016 are incomplete, so calculations through 2015 are reported.

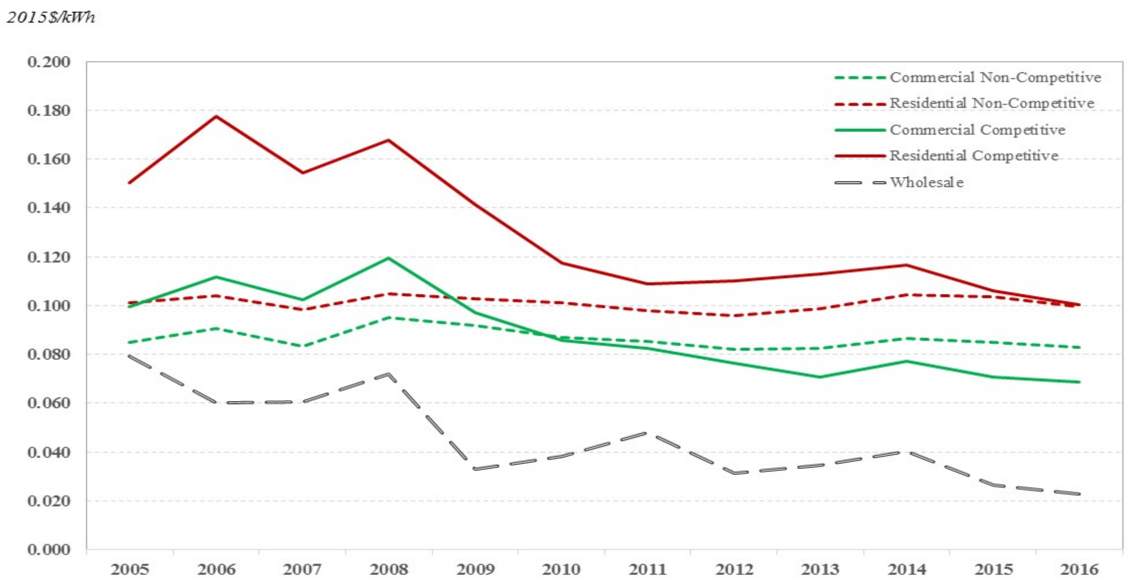
In Figure 8, we have graphed a composite price for commercial electricity for competitive and non-competitive market areas alongside a composite price for residential electricity for competitive and non-competitive market areas and a composite wholesale price. The composite prices are averages across market areas for the data in the sample. These are meant to be illustrative only. In particular, the data highlight an important point about relative pricing across sectors in competitive versus non-competitive areas. Namely, the spread between residential and commercial prices in non-competitive areas is much smaller than in competitive areas. Moreover, while residential rates across market areas have converged over the sample period (see above for more discussion), commercial rates have diverged, with those in competitive areas seeing a growing discount relative to non-competitive areas. Indeed, a similar phenomenon is observable on a national level (see Figures 1 through 3).

While there may be multiple explanations for the observations based on Figures 7 and 8, the data are consistent with a policy of cross-subsidizing residential customers with higher rates on commercial customers in non-competitive market areas. Such a policy is possible if a particular customer class has a lower elasticity of demand, meaning they are more subject to price discrimination with limited price responsiveness.[17] Such might be the case for commercial customers because relocating their business activities away from their customers or employees in response to a change in energy price can compromise the firm's economic model. Discriminatory pricing would be more likely in a regulated market

[17] For studies of cross-subsidization evidence between customer groups, see, for example, Steiner (2001), Hattori and Tsutsui (2004), and Erdogdu (2011). For studies of cross-subsidization between electricity sectors, see, for example, Eid, Guillén, Marín, and Hakvoort (2014), EEI (2013), and Pérez-Arriaga, et al. (2013).

area than in a competitive one because competition should force all electricity providers to charge prices that reflect the overall marginal cost of service.

Figure 8. Average Rates Across Sectors by Aggregate Market Area*



Data sources: See text for description

*Commercial data for 2016 are incomplete, so year-to-date data is indicated. Also, note that the data presented are the respective annual averages across all competitive and non-competitive areas. Therefore, the data are representative and do not capture seasonal variations in rates or the disparity in rates within the non-competitive areas in particular.

We are continuing to collect data from large commercial consumers across the state of Texas. Subsequent analysis will further evaluate the evidence that commercial users are being billed in a way that effectively cross-subsidizes residential users. It should be noted that while such a pricing policy may seem viable and perhaps even desired, particularly if residential consumer welfare is prioritized by the electricity service provider, it may be myopic as it ignores the adjustments that commercial entities can make. Specifically, while many commercial entities are not likely to relocate on the basis of higher electricity rates, they may be able to offset electricity costs through investments in on-site generation. As more commercial users are incentivized to move off grid, the local electricity service provider will be forced to raise rates to other customers in order to cover its costs. A cross-subsidized rate to residential customers thus may be unsustainable.

VI. Concluding Remarks

Passage of Senate Bill 7 in 1999 launched Texas electricity market reform, but substantive changes did not begin until 2002. The evolution of wholesale and retail electricity market prices since has been dynamic, but competition has yielded an outcome consistent with what economic theory predicts. Namely, retail prices have declined relative to wholesale prices in competitive market areas.

At the residential level, prices were much higher in competitive areas than in non-competitive areas when reforms were first implemented—but they have since fallen to a point of parity with non-competitive market areas. This outcome highlights the importance of evaluating market dynamics over time rather than focusing on sample averages. Thus, residential consumers in competitive areas paid a higher average price for electricity from January 2002 through December 2016 than did customers in non-competitive areas. But this fact masks the underlying trends that market reforms have wrought. While the average price paid by residential customers in 2002 in areas that subsequently became competitive was between two and three cents higher than the rates paid in areas that remained non-competitive, this was before competition could have had any impact. More importantly, residential prices declined in all competitive market areas from 2002 to 2016, while they increased in all non-competitive market areas over the same time period. As a result, by 2016, the average price paid by residential customers in competitive market areas was lower than the average price paid in non-competitive market areas.

In addition, while wholesale electricity prices declined from 2002 to 2016, with a significant increase in the interim, the declines observed in residential prices in competitive market areas were generally larger than the declines in wholesale prices. This is consistent with a market in which competitive electricity service providers are realizing efficiency gains and cost reductions.

Overall, the changes in wholesale and residential prices from 2002 to 2016, and the patterns of volatility in the price series, support the notion that retail prices clearly reflect wholesale prices in competitive market areas. Indeed, the econometric analysis consistently indicated a positive and statistically significant relationship between wholesale price and residential price across competitive market areas. This suggests that allowing competition in markets has delivered the intended result.

We also found that trends in the commercial electricity billing and load data that have been collected to date reveal an outcome that is consistent with the analysis of residential price data. The relative prices between the commercial and residential sectors across competitive and non-competitive market areas also support the notion that competition forces electricity service providers toward pricing power at overall marginal cost. While commercial rates in competitive areas track wholesale prices, the evidence is mixed in non-competitive market areas. This reinforces the results from the analysis of residential prices that a lack of competition allows greater divergence between price and marginal cost. Furthermore, the differences between residential and commercial prices in the two types of areas is consistent with non-competitive suppliers exercising a degree of market power to redistribute from commercial to residential customers. In particular, the data reveal that price reductions for commercial customers in non-competitive market areas have not generally been forthcoming, despite the fact that wholesale prices have declined.

In sum, the data analyzed herein support the notion that prices have behaved exactly as economic theory would indicate in competitive market areas. There are still research questions to be addressed. For example, more research is needed to understand the objective of suppliers in non-competitive areas. Multiple hypotheses could explain the pricing paradigms we have observed. One obvious challenge is in data collection, since data on electricity loads, which are necessary when considering non-competitive markets, may not be readily available for each market area. We endeavor to address this and other questions by collecting data from large commercial users across the state of Texas, which will provide a unique opportunity to more rigorously evaluate how individual sites compare across market areas.

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Appendix

Table A1. Parameter Estimates (500kWh Customers)

		Non-Competitive Regions								Competitive Regions				
Variable	**Parameter**	**SWPS**	**SWEP**	**Magic Valley**	**Upshur**	**Victoria**	**Austin Energy**	**CPS**	**San Marcos**	**AEP-CTX**	**AEP-NTX**	**Oncor**	**Reliant/CPT**	**TX-NM**
Constant	α_0	0.010132	-0.001537	0.100811	0.010376	0.054471	0.032376	0.095389	0.022736	-0.002627	-0.015108	-0.008929	-0.002375	-0.014455
	std err	0.010650	0.011392	0.019593	0.005566	0.013912	0.007814	0.014863	0.011891	0.017024	0.028435	0.008427	0.009545	0.009155
$L.p^{res}$	α_1	0.693943	0.628157	0.497465	0.871766	0.729213	0.642903	0.249113	0.841873	0.818640	0.656834	0.860657	0.858541	0.885477
	std err	0.027867	0.034009	0.038881	0.022767	0.025879	0.035520	0.052596	0.026689	0.016717	0.027370	0.012515	0.013186	0.013093
p^w	α_2	0.032988	-0.016704	0.178157	0.011390	0.005295	-0.024162	0.071334	0.014786	0.046827	0.078676	0.064246	0.059423	0.061037
	std err	0.019086	0.020734	0.030669	0.010087	0.020780	0.012127	0.022022	0.019044	0.025409	0.050135	0.011566	0.011572	0.012213
w	α_3	0.000008	0.000016	-0.000017	0.000000	-0.000007	0.000001	-0.000021	-0.000002	0.000017	0.000037	0.000015	0.000012	0.000016
	std err	0.000006	0.000006	0.000010	0.000003	0.000007	0.000004	0.000007	0.000006	0.000009	0.000016	0.000005	0.000005	0.000005
D^{pb}	α_4	-0.000932	0.001820	-0.012131	0.000573	-0.010903	-0.002828	0.011471	-0.003531	-0.009137	-0.013787	-0.005158	-0.006043	-0.003138
	std err	0.001948	0.002099	0.003685	0.001011	0.002672	0.001401	0.002580	0.002323	0.003394	0.005385	0.001784	0.001988	0.001793
t_1	α_5	0.000115	0.000054	0.000121	0.000028	0.000125	0.000111	-0.000077	0.000079	0.000190	0.000442	0.000124	0.000127	0.000067
	std err	0.000036	0.000036	0.000060	0.000019	0.000043	0.000025	0.000043	0.000040	0.000058	0.000101	0.000030	0.000033	0.000031
t_2	α_6	0.000039	0.000015	-0.000048	0.000030	-0.000008	-0.000001	0.000147	-0.000009	-0.000064	-0.000106	-0.000044	-0.000042	-0.000031
	std err	0.000013	0.000014	0.000024	0.000008	0.000016	0.000009	0.000019	0.000015	0.000022	0.000035	0.000012	0.000013	0.000012
Feb	α_7	0.000498	0.006245	-0.006328	-0.000229	-0.001429	-0.000864	0.001464	-0.001454	0.000481	-0.000365	0.000153	0.000781	0.000357
	std err	0.001542	0.001619	0.002628	0.000779	0.001845	0.001069	0.001931	0.001707	0.002483	0.004130	0.001228	0.001382	0.001338
Mar	α_8	0.000017	0.004324	-0.004414	-0.000487	-0.001625	-0.001003	0.008015	-0.000622	0.001929	-0.003306	-0.000114	0.000237	-0.000325
	std err	0.001540	0.001635	0.002622	0.000779	0.001844	0.001067	0.001931	0.001705	0.002480	0.004124	0.001227	0.001382	0.001337
Apr	α_9	-0.000215	0.007054	-0.004151	-0.000571	0.000314	-0.001313	0.002914	-0.000023	0.005105	0.005261	0.000642	0.001256	0.000118
	std err	0.001540	0.001615	0.002625	0.000778	0.001844	0.001067	0.001981	0.001705	0.002480	0.004126	0.001227	0.001382	0.001337
May	α_{10}	-0.000359	0.016081	-0.004648	-0.000069	-0.002789	-0.001114	0.005487	-0.003567	-0.001632	0.002131	0.001766	0.001896	0.001230
	std err	0.001542	0.001614	0.002633	0.000778	0.001856	0.001070	0.001954	0.001711	0.002488	0.004127	0.001227	0.001384	0.001337
Jun	α_{11}	0.008353	0.008912	-0.006216	-0.000989	-0.002327	0.002638	0.006226	-0.002623	0.002107	0.000381	0.002284	0.001158	0.000982
	std err	0.001550	0.001684	0.002652	0.000782	0.001865	0.001078	0.001986	0.001725	0.002501	0.004147	0.001230	0.001388	0.001341
Jul	α_{12}	0.002276	0.010102	-0.005453	0.000508	-0.003955	0.000137	0.007052	0.001212	0.000884	-0.000659	0.000126	-0.000269	-0.000824
	std err	0.001565	0.001686	0.002636	0.000783	0.001851	0.001077	0.001991	0.001715	0.002487	0.004165	0.001231	0.001385	0.001344
Aug	α_{13}	0.001024	0.006735	-0.012604	-0.001219	-0.004342	0.000217	0.002732	-0.001817	-0.001509	-0.002928	-0.001501	-0.002217	-0.002527
	std err	0.001649	0.001750	0.002683	0.000806	0.001886	0.001100	0.002039	0.001747	0.002530	0.004304	0.001250	0.001403	0.001370
Sep	α_{14}	0.004025	0.008083	-0.011119	-0.000728	-0.004103	-0.000315	0.002278	-0.001506	-0.001167	-0.003911	-0.000677	-0.001183	-0.000500
	std err	0.001547	0.001662	0.002616	0.000779	0.001841	0.001073	0.001961	0.001708	0.002482	0.004133	0.001228	0.001383	0.001339
Oct	α_{15}	-0.004827	0.006276	-0.015027	-0.000190	-0.003078	-0.004240	0.003449	-0.000945	-0.000478	-0.001169	-0.000240	-0.000542	-0.000209
	std err	0.001553	0.001661	0.002701	0.000779	0.001843	0.001073	0.001944	0.001711	0.002484	0.004136	0.001228	0.001384	0.001339
Nov	α_{16}	-0.000949	-0.002501	-0.006452	-0.001601	-0.001421	-0.001496	0.001028	-0.001553	0.000969	0.000396	0.001534	0.001664	0.000911
	std err	0.001540	0.001646	0.002601	0.000770	0.002017	0.001057	0.001924	0.001714	0.002452	0.004138	0.001214	0.001366	0.001322
Dec	α_{17}	0.002667	0.003659	-0.006458	-0.000303	0.002973	-0.001457	-0.000532	0.001457	-0.000678	0.000704	-0.000068	-0.000016	-0.000556
	std err	0.001572	0.001641	0.002661	0.000792	0.001882	0.001086	0.001965	0.001739	0.002524	0.004202	0.001249	0.001406	0.001361

Note: Parameter values in gray are not statistically significant at a 10% level. Parameter values in blue are statistically significant at the 10% level, parameter values in red are statistically significant at the 5% level, and parameter values in black are statistically significant at the 1% level. Parameter estimates for the D_i^{pro} are not reported, but are significant at the 1% level and are available upon request.

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Citizens for Energy Choices

SUBJECT: Financial Impact Statement for the Amendment: Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice ("Energy Choice Amendment")

DATE: March 4, 2019

This third memorandum from the sponsors of the Energy Choice Amendment to the FIEC is intended to provide additional information on issues raised at the FIEC Principals' Workshop held on February 21, 2019. This memorandum provides additional information regarding topics discussed extensively by opponents to the Amendment, or raised by the FIEC Principals. Specifically, this memorandum addresses: I) the definition of an "Investor-Owned Utility" ("IOU") as the phrase is used in the Amendment; II) whether the Amendment would allow an incumbent IOU to own the transmission and distribution facilities it is likely to operate following restructuring of the market; III) the Amendment's impact on the ability of an incumbent IOU to transfer ownership of electricity generating assets, marketing business functions and its various contracts, to a corporate affiliate or parent; IV) the topic of takings and stranded costs; and 5) the formation of an Independent System Operator to facilitate a competitive wholesale market and an Independent Market Monitor to monitor it.

I. What is an "Investor Owned Utility"?

Current Law

The meaning of the term "investor-owned utility" is self-evident. So much so that the term is frequently used in Florida Statutes, but is not defined. Indeed, with regard to electric utilities, Ch. 366 broadly defines the term "electric utility" as "any municipal electric utility, *investor-owned electric utility*, or rural electric cooperative which owns, maintains, or operates an electric generation, transmission, or distribution system within the state." Section 366.02(2), Fla. Stat. (emphasis added).

Section 366.8255, Florida Statutes, which authorizes electric utility recovery of specified environmental compliance costs outside of base rates through application of an annually adjusted cost factor, defines the term "electric utility" to include any *investor-owned electric utility* that owns, maintains, or operates an electric generation, transmission, or distribution system within the State of Florida and that is regulated under this chapter." (emphasis added)

Section 366.82, Florida Statutes, which requires the Florida Public Service Commission ("FPSC") to establish goals for each "utility" for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems, specifies that "[t]he commission is authorized to allow an *investor-owned electric utility* an additional return on equity of up to 50 basis points for exceeding 20 percent of their annual load-growth through energy efficiency and conservation measures. The additional return on equity shall be established by the commission through a limited proceeding." (emphasis added)

It is clear, both from the self-evident wording of the term, and from the regulatory regime established in Florida Statutes, that an investor-owned utility is one in which its owners have invested capital and are entitled to a fair opportunity to earn an authorized rate of return on their investment. In other words, under current law, investor-owned utilities are those utilities that are subject to the FPSC's rate-of-return regulations.

The FPSC likewise recognizes the self-evident meaning of the term "investor-owned utility" as it is also used frequently within Chapter 25 of Florida's Administrative Code and within FPSC Orders without definition.

General Industry and Common Language Understanding

The foregoing meaning of the term "investor-owned utility" is consistent with the general understanding of the term within the electric utility industry. For example, the U.S. Energy Information Administration's Glossary defines an "investor-owned utility" as "[a] privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return." Likewise, North Carolina State University's North Carolina Electric Meter School and Grid Technology Conference Glossary of Terms for the Electric Utility Industry defines an IOU as "[a] utility company whose assets are owned by investors and whose stock is publicly traded." Numerous other organizations provide the same definition. In Florida, each of the five for-profit utilities are regarded as investor owned utilities, though it is clear that they need not be "publicly traded" companies to be considered "investor owned." These companies are affiliate operating companies owned by a corporate parent holding company that is publicly traded. For example, Florida Power & Light Company is owned by NextEra Energy, Inc., whose stock is publicly traded. NextEra Energy, Inc., is not itself an "investor-owned utility" because it is the parent to unregulated subsidiaries that operate in competitive markets.

Additionally, the online Cambridge Dictionary (dictionary.cambridge.org) defines an "investor" as "a person or group of people that puts its money into a business or other organization in order to make a profit." Other dictionaries provide definitions with no substantive difference. Thus, in common English, an investor-owned utility would be a utility that is owned by a person or a group of people that puts its money into the utility's business in order to make a profit.

Energy Choice Amendment's Use of the Term

As discussed above, the meaning of the term "investor-owned" is self-evident to a degree that neither the Florida Legislature nor the FPSC has perceived a need to define it. It seems obvious that a Court faced with interpreting the Energy Choice Amendment should have little difficulty understanding the meaning of the term. Indeed, when required to interpret the meaning of undefined terms included in the law or in legal documents, Courts rely upon well-established rules of interpretation that are easily applied in this instance. Whether a Florida Court interprets the phrase based on its current understanding in Florida law, or based on common usage within the industry, or based on common English usage of its constituent words, it will make no difference, as each such understanding is substantively the same.

II. T&D Ownership by IOUs

The Amendment's Language

Subsection (c) of the Energy Choice Amendment requires the Legislature to enact implementing language that, among other things, "entitles electricity customers to purchase competitively priced electricity, including but not limited to provisions that are designed to (i) limit the activity of investor-owned electric utilities to the construction, operation, and repair of electrical transmission and distribution systems… ."

Opponents of the Energy Choice Amendment argue that, because the word "ownership" is not included among the list of activities to which an IOU should be limited, this language could prohibit the Legislature from allowing incumbent IOUs to continue owning their transmission and distribution systems after restructuring, resulting in a host of negative financial impacts. This argument is baseless.

First, by its express terms, the provision in question addresses limitations not on ownership, but on certain "activit[ies]" of IOUs. In common parlance, ownership is not an "activity" but a state of entitlement, possessory right and proprietorship. The enumerated "activities" go hand-in-hand with ownership. "Owners" commonly construct, operate and repair their own property and facilities, and only an unnecessarily strained interpretation would compel a different meaning.

Second, contrary to the opponents' claims, nothing in the Amendment's language requires the Legislature to prohibit incumbent IOUs from owning transmission and distribution systems following market restructuring. Rather, the text states that "the Legislature shall adopt complete and comprehensive legislation to implement this section in a manner fully consistent with its broad purposes and stated terms… ." Legislation allowing incumbent IOUs to own rate-regulated transmission and distribution systems would in no way be inconsistent with the Amendment's broad purposes and stated terms.

The Amendment's broad purposes are set out in its Policy Declaration and in its grant of rights to electricity customers. These broad purposes include: 1) creating fully competitive wholesale and retail electricity markets; 2) affording customers meaningful choices among a wide variety of competing electricity providers; and 3) preserving the right of electricity customers to be able to choose an electricity provider from among multiple providers in competitive wholesale and retail electricity markets. The Legislature's choice to allow the ownership of transmission and distribution facilities by incumbent IOUs operating strictly as rate-regulated T&D companies would in no way impede these broad purposes.

Third, to interpret the limitation on IOU activities in the strained manner advanced by the opponents of the initiative would violate well-recognized rules of interpretation that Florida courts have long embraced. Even assuming for the sake of argument that the limiting clause left the language open to multiple interpretations, Florida courts will reject any interpretation that would lead to "unreasonable, absurd or harsh consequences." Hardee County v. FINR II, Inc., 221 So. 3d 1162 (Fla. 2017); Florida Dept. of Envl. Protection v. Contractpoint Florida Parks, LLC, 986 So. 2d 1260 (Fla. 2008); Woodall v. Travelers Indem. Co., 699 So.2d 1361 (Fla. 1997); Tampa-Hillsborough County Expressway Auth. v. K.E. Morris Alignment Serv., Inc., 444 So. 2d 926, 929 (Fla. 1983); Armstrong v. City of Edgewater, 157 So.2d 422 (Fla. 1963).

By providing that implementing legislation should be "designed to … limit the activity of investor-owned electric utilities to the construction, operation, and repair of electrical transmission and distribution systems," this provision is clearly aimed at limiting IOUs to the customary activities of T&D companies, thus preventing them from engaging in activities associated with electricity generating wholesalers or electricity marketing retailers. The provision is not designed to prevent IOU's from engaging in the myriad of functions attendant to and typically associated with corporate ownership and operations.

An interpretation holding that the absence of the word "ownership" from this list of activities prohibits an IOU from owning the T&D system it constructs, operates, and repairs would lead to unreasonable, absurd, or harsh results. Following the logic of such an interpretation, every one of the thousands of other functions incumbent IOU T&D companies could undertake would also be prohibited because the sentence in question failed to specify each and every one of them. That interpretation would also prohibit, for example, maintenance of the system by the IOU operator, replacement of system components by the IOU operator, IOU back-office functions such as accounting and management, operation of executive offices, and any other function T&D companies might undertake that is not included in the three-item list. While the sponsor's interpretation would not result in an unreasonable or arbitrary outcome, the one proposed by the opponents clearly would do so and it would be at odds with the broad purposes of the Amendment by frustrating the Legislature's ability to establish a competitive retail electricity market that is beneficial to consumers.

III. Divestment of Assets

What the Amendment Requires Regarding Electricity Generating Assets

As articulated above, the Energy Choice Amendment does not require the Legislature to implement wholesale and retail competition by requiring an incumbent IOU to divest ownership of its T&D assets. It is anticipated that following restructuring of the electricity markets in Florida, Florida's incumbent IOUs will continue to operate as rate-regulated T&D companies that own the T&D systems and facilities they operate.

With regard to an incumbent IOU's ownership of electricity generating assets, the Energy Choice Amendment would require Florida's incumbent IOUs to divest ownership of those assets, as implementing Legislation within the requirements of the Energy Choice Amendment must limit IOUs to the common functions of T&D-only companies.

As explained above, Florida's IOUs are operating companies owned by publicly traded corporate-parent holding companies operating regulated and unregulated businesses in Florida and throughout North America, and in some cases, the world. The corporate parent is not an electric IOU, as that term is commonly understood. If it were, then the same classification would necessarily be attributed to the holding company's numerous unregulated businesses, including any competitive retail or electricity generating businesses it holds and controls throughout the many jurisdictions in which its subsidiaries operate. Such an interpretation of the meaning of the term "investor-owned utility" would be an unreasonable overreach contrary to the broad purposes and stated terms of the Energy Choice Amendment, and would almost certainly be rejected by any Florida court, as discussed above.

Consequently, nothing in the Energy Choice Amendment prohibits the Legislature from implementing the Amendment so that an incumbent IOU's corporate parent, or an unregulated affiliate owned by the corporate parent, may own electricity generating assets operating in Florida's newly restructured wholesale markets. As long as it observes the requirements of the Amendment (promote wholesale and retail competition and limit market power), the Legislature has broad discretion in facilitating the transfer of electricity generating assets from incumbent IOU operating company ownership, to ownership by the corporate parent through a subsidiary established to operate in Florida’s newly established competitive wholesale marketplace.

Such corporate restructuring would enable the incumbent IOU’s investors to maintain their equity stake in the assets, would allow them to continue to achieve a return on their investment (though with new business risk), and would minimize the impact, if any, to the value of the assets that could result from a change in the financial strength of the owner.

Assignability of Contracts

The Energy Choice Amendment’s opponents surmise that market restructuring required by the Amendment will cause the cancellation of bulk power agreements to which IOUs are a party. Since the Amendment’s requirements prohibit an IOU from operating as an electricity generator, they argue, their contracts as electricity suppliers will be cancelled, and some of these contracts are for the supply of energy and capacity to municipal electric utilities. While such contracts with the potential to be affected also exist between two IOUs, between IOUs and Rural Co-ops; and between independent small power producers that are “qualifying facilities” under federal law, only those between an IOU and a municipal utility relate to potential impacts to local government costs and revenues.

While it is possible that bulk power agreements between IOU wholesale suppliers and municipal electric utilities may be impacted by the market restructuring required by the Energy Choice Amendment, it is not an inevitability that they will be terminated. Many such contracts contain provisions that allow the parties to address such situations.

Under Florida law, a contract is presumed to be assignable unless its terms specify otherwise. What that means is, either party to a contract has the ability to assign its rights and obligations under the contract to another party willing to accept them. Most commercial agreements have provisions that address whether the contract is assignable and under what conditions. Bulk power agreements are no different. However, it is customary to include language in these agreements allowing assignment only upon the agreement of the other party. That language typically indicates that the consent for assignment cannot be unreasonably withheld. Depending on circumstances unknowable at this time, it may be possible for an IOU to assign its rights and responsibilities under such a contract, whether it be as a wholesale electricity supplier or purchaser, to a non-IOU affiliate within the same corporate family.

Additionally, many such contracts contain language enabling the parties to negotiate additional terms to address changes in the law that would make performance of the contract otherwise illegal for one of the parties. Without access to each such agreement for review, and a detailed review of the financial impact law changes have on the business relationship governed by each contract, it is not possible to determine the probable impact that the Energy Choice Amendment will have on local government costs or revenues.

IV. Takings, Compensability & Stranded Costs

The IOUs make a claim of entitlement to "stranded cost" recovery. Such claims are predicated on legal theories that do not necessarily guarantee any stranded cost recovery from courts, as the law is not settled on the point. Further, in light of the absence of judicially determined entitlement to recovery of such costs, any such recovery can only be based on future government action, which is speculative. It is therefore impossible to state that any stranded cost recovery is probable, let alone any particular amount. Assuming for the sake of argument that an IOU that experiences stranded costs as a result of restructuring in Florida's electricity markets would be entitled to some form of cost recovery, whether and to what extent such stranded costs exist would need to be determined, likely following a thorough review of financial and accounting data, perhaps in adversarial administrative proceedings. IOUs tend to grossly overstate their entitlement in such proceedings, and can be expected to have done so in any presentation made to the FIEC.

One theory for stranded cost recovery advanced by IOUs is based on the concept of a "regulatory compact." Under this theory, the IOU is obligated to provide service within its state protected service territory, and in return for providing its services on demand to any customer who requests it, the Legislature has established a regulatory authority (FPSC) that ensures the financial integrity of the IOU by allowing it to recover its prudently incurred costs plus a reasonable rate of return on its owners' investment. This theory posits that the "regulatory compact" is some kind of implied contract between the IOU and the state that when breached, may be enforced against the state for some measure of damages. Further, the claim asserts added constitutional dimensions because the Constitution prohibits the state from interfering in certain contracts. These contract theories have little legal support.

Stranded cost recovery claims are also grounded in takings jurisprudence, which is far too complex to be addressed comprehensively in this memorandum. In short, regulatory takings jurisprudence has developed in more than one line of cases. One line addresses the issue in the land use context, while another line addresses the issue in the context of infrastructure industries like utilities, telecommunications companies and common carriers. The level of deference afforded government action in these two lines of jurisprudence is very different, with the court being far more deferential to government action as it relates the establishment of compensatory rates for regulated infrastructure companies.

Under the IOUs' takings theory, once the regulatory compact is breached by a regulatory change, there is a taking of private property because the new regulatory scheme enabling competition has eliminated the ability of an IOU's owners to realize reasonable investment-backed expectations for recovery of the investment and a reasonable profit, as there is no longer a captive customer base to provide the needed revenue to meet the expectation. Because of its "regulatory taking," the state is obligated to compensate the IOU for its "stranded costs." Note that this theory utilizes a concept of "investment-backed expectations" which is an element of analysis developed in the land use regulatory takings jurisprudence, a line of cases that is less deferential to government action.

Neither of these lines of jurisprudence directly apply to the problem of measuring and determining liability for "stranded costs" (or "stranded benefits") that may result from regulatory changes that restructure electricity markets. There are no cases that judicially acknowledge a constitutional or common law right to recovery of stranded costs. The stranded cost recovery that has been realized by IOUs to date is the result of a regulatory mechanism, such as that allowed by FERC based on its orders opening access to interstate transmission facilities (presumably due to the analogy with "physical invasion" takings cases related to the FCC's actions opening access to incumbent phone carriers' poles and wires) or pursuant to agreements made to settle litigation.

In their article *Disentangling Deregulatory Takings*, Ackerman and Rossi provide a thorough overview of regulatory takings jurisprudence and a discussion of entitlement to stranded costs. Their article is attached as **Appendix A**. In it, the authors state:

> The takings argument might therefore seem the more plausible argument in favor of legal recovery of stranded costs. But those making the claim for deregulatory takings face several daunting obstacles.
>
> First, as discussed above, United States takings jurisprudence has not found that regulatory actions in infrastructure industries demand compensation. Procedural guarantees and political accountability are sufficient, although those pressing for deregulatory takings also argue that this approach is in need of reform. Supporters of a legal entitlement to compensation would abandon the deferential tradition of *Hope*, *Market Street Railway*, *Permian Basin* and *Duquesne*, instead treating deregulatory takings cases as similar to land use takings. The land use cases are weak precedents, however, because unlike individual property owners, utility investors appear to be adequately protected in the political and regulatory process. It is not clear that deregulation has challenged this rationale. The Takings Clause should not be used to protect those who have had a chance to influence policy or who are in a position to anticipate future changes in policy and take them into account in their investment decisions.
>
> Second, as we argued above, there are seldom explicit contracts guaranteeing regulated firms a certain rate of return on their assets or promising to indemnify them against future changes in policy. Thus, firms should have internalized these risks in making their investment choices. Supreme Court opinions in ratemaking cases generally require utility owners to accept the risks of unsuccessful investments.

> Third, it is not at all clear that utilities were induced to invest by eager regulators, only to be surprised when regulators changed the rules for rate recovery in mid-course. Instead, some commentators argue that firms, as well as regulators, supported high levels of investment, fully aware of the risks of less than full recovery of the costs. Indeed, if firms anticipate that their costs will be reimbursed no matter what the competitive environment, they have an incentive to overinvest. Assured compensation affects the incentives for strategic behavior inherent in the relationship between the regulated firm and the regulatory agency officials. One result may be to exaggerate the Averch-Johnson effect under which firms select inefficiently high capital/labor ratios."
>
> To date, no court has accepted the sweeping deregulatory takings argument advocated by the industry. Where the breach of contract claim has been raised, courts have uniformly required clear and explicit contracts as a basis for protection of the utility's interest in stranded cost recovery. Outside of cases involving physical invasion for access to network wires, the takings claims have been rejected by the courts. Even though the courts have refused to accept deregulatory takings claims, deregulatory takings lawsuits have resulted in settlements – sometimes imposing transition surcharges that will cost consumers billions – and have influenced the adoption of consumer surcharges and access charges at the state and federal levels. The very success of public utilities in having their interests heard at the state level is an argument against applying the Takings Clause to require compensation. Although the firms will not always win all the compensation they want, utilities are clearly an important force in state politics that are well able to raise their concerns within existing institutions and procedures.

(internal citations omitted).

Aside from the question of an IOU's legal entitlement to any stranded cost recovery, there are other complex questions – 1) Do such costs exist, or are there instead stranded benefits? 2) What method is used to value the assets for which stranded cost recovery is sought? 3) To what degree have the assets depreciated and how has that been treated by the company and by regulators? 4) If such costs do exist, have regulators already factored in the risk of market changes when allowing cost recovery?

For example, with regard to question 4 above, the FPSC has already, at least partially, addressed the impacts that could result from competition in the retail electric market, and actually issued an order of its own, several weeks before FERC's issuance of Order 888, approving a proposal by FPL to charge and record a "fixed and permanent" amortization expense for its nuclear generating units. In its proposal to the PSC, FPL argued that the amortization schedule was necessary to stave off the impacts of potential stranded investments. The extent to which this FPSC Order and numerous other rate and accounting treatments authorized by the FPSC or the Legislature to allow asset cost recovery outside of base rates, such as the nuclear cost recovery clause, the environmental cost recovery clause, the “Generation Base Rate Adjustment” mechanism, the “Solar Base Rate Adjustment” mechanism, and others, have insulated the IOUs from the risk of failed or stranded investments is unknown without in-depth analysis by independent experts. All of these cost recovery mechanisms, except the new Solar Base Rate Adjustment, which are in addition to the nuclear amortization expense granted to FPL, have been described by FPSC staff in a 2008 study of decoupling, as having “inherently decoupled” from 53 to 69 percent of utility costs from base rates.

The IOUs’ judicial entitlement to any stranded costs is uncertain. Whether they might be granted such cost recovery by the Legislature or as a settlement of litigation is speculative. Whether stranded costs even exist and in what amount is unknown for a variety of reasons – the only data provided has been supplied by the IOUs, and is unreliable due to the absence of any critical evaluation of it. Finally, until such costs are determined and some mechanism is developed to address the costs, it is impossible to know what impact on state and local government revenues and costs such a stranded cost obligation may create. Therefore, any statement regarding the existence of, the IOUs’ entitlement to, or the impact to state and local government revenues or costs from IOU stranded costs would be purely speculative. Certainly, it is not possible to determine at this time that any particular outcome is probable.

V. Establishment of Independent System Operator (ISO) and Independent Market Monitor (IMM)

Unless it joins an existing Independent System Operator (“ISO”) or Regional Transmission Organization (“RTO”), Florida will need to establish its own ISO and Independent Market Monitoring (“IMM”) entities. Indeed, the Energy Choice Amendment requires the Legislature’s implementation to contain provisions designed to “establish an independent market monitor to ensure the competitiveness of the wholesale and retail electric markets.”

Properly done, a new Florida ISO would be best formed following the model of the ERCOT ISO in Texas. Based on this experience, such an “Independent Organization” in Florida would likely be:

- An independent, non-profit organization overseen by regulators;
- Organized to perform the following functions:

1. Administer the operational and market functions of the electric market system, including procuring and deploying ancillary services, scheduling resources and loads, and managing transmission congestion, as set forth in Florida’s laws, rules and orders, and ISO rules;
2. Administer settlement and billing for services provided by the ISO, including assessing creditworthiness of market participants and establishing and

enforcing reasonable security requirements in relation to their responsibilities under ISO rules;

3. Serve as the single point of contact for the initiation of transmission services;
4. Maintain the reliability and security of the ISO region's electrical network, including the instantaneous balancing of ISO generation and load and monitoring the adequacy of resources to meet demand;
5. Provide for non-discriminatory access to the transmission system, consistent with Florida's Statutes, rules and orders, and ISO rules;
6. Accept and supervise the processing of all requests for interconnection to the ISO transmission system from owners of new generating facilities;
7. Coordinate and schedule planned transmission facility outages;
8. Perform system screening security studies, with the assistance of affected utilities;
9. Plan the ISO transmission system;
10. Establish and administer procedures for the registration of market participants;
11. Manage and operate the customer registration system;
12. Administer renewable energy programs, unless the commission designates a different person to administer the program;
13. Monitor generation planned outages;
14. Disseminate information relating to market operations, market prices, and the availability of services, in accordance with this chapter, commission orders, and the ISO rules;
15. Operate an electronic transmission information network; and
16. Perform any additional duties required under Florida Statutes, rules and orders, and ISO rules.

While certain aspects of reliability are and would continue to be overseen by the SERC Reliability Corporation,[1] a number of ISOs in other jurisdictions contract with an independent third party to perform the IMM functions, which might include the following:

1. Detecting and preventing market manipulation strategies and market power abuses;
2. Evaluating the operations of the wholesale market, current market rules, and proposed changes to the market rules;
3. Recommending measures to enhance market efficiency;

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[1] From a press release issued by the FRCC: "On October 30, 2018, the Florida Reliability Coordinating Council, Inc. (FRCC), Board of Directors approved a timeline and plan to terminate its Amended and Restated Delegation Agreement with the North American Reliability Electric Reliability Corporation (NERC) pending the receipt of formal approval of FRCC's plan from NERC and the Federal Energy Regulatory Commission. FRCC will target winding down its Regional Entity operations effective July 1, 2019. … After July 1, 2019, FRCC will continue its traditional member services reliability functions and coordinating roles, which include its work as a Reliability Coordinator and Planning Authority. In fulfilling these roles, "FRCC staff and members will continue to steadfastly pursue our vision to maintain a highly reliable and secure bulk power system for peninsular Florida," said FRCC CEO Stacy Dochoda."

4. Monitoring all markets in the Florida power region for energy, capacity services, and congestion revenue rights, and the ISO protocols and related procedures and practices that affect supply, demand, and the efficient functioning of such markets;
5. Developing and regularly monitoring market screens and indices to identify abnormal events in the power region's wholesale markets;
6. Analyzing events that fail the screens and other abnormal activities and market events, using computer simulation and advanced quantitative tools as necessary;
7. Developing and regularly monitoring performance measures to evaluate market participants' and ISO compliance with the ISO protocols and operating guides;
8. Assessing the effectiveness of ISO management of the energy, ancillary capacity services, and congestion rights markets operated by ISO, and evaluating the effectiveness of congestion management by ISO;
9. Conducting market power tests and other analyses related to market power determination;
10. Analyzing the ISO protocols and other market rules and proposed changes to those rules to identify opportunities for strategic manipulation and other economic inefficiencies, as well as potential areas of improvement;
11. Conducting investigations of specific market events;
12. Providing expert testimony services relating to the IMM's independent analysis, findings, and expertise;
13. Maintaining a market oversight website to share market information with the public;
14. Preparing market monitoring reports as required by regulators;
15. Recommending to regulators measures to enhance the efficiency of the wholesale market and methods to correct market design flaws it has identified; and
16. Performing any additional duties required by regulators within the scope of the applicable Statutes and rules.

Florida’s implementation could potentially grant the IMM the following authority:

1. Authority to conduct monitoring, analysis, reporting, and related activities (but without enforcement authority, which would likely be performed by regulators).
2. Authority to question a market participant about activities that may violate regulatory rules or ISO protocols, or about potential market manipulations. The IMM may inform a market participant that its activities may be in violation of regulatory rules or ISO protocols or operating guides, subject to the restrictions established by regulators.
3. Authority to require submission of any information and data it considers necessary to fulfill its monitoring and investigative responsibilities by the ISO and by market participants. Market participants and the ISO should be

required to provide complete, accurate, and timely responses to all IMM requests for documents, data, information, and other materials.

4. Authority to require that each market participant designate one or more points of contact that can answer questions the IMM may have regarding a market participant's operations or market activities.

The costs of both a new ISO and the IMM could potentially be paid for by revenue of the Florida ISO derived from an administrative fee charged on all MWh sold on the wholesale market. By way of example, the administrative fee for ERCOT since January 1, 2016 has been $0.555/MWh (average real-time price $28.25/MWh); in early 2002, it was $0.22/MWh (average price of energy $25-$35/MWh). Additional fees can be imposed that are charged based on actual costs incurred – for example, the costs of interconnection studies and application fees can be paid for by the entities requesting the services in question.

It is impossible to know whether and how much the establishment of an ISO and an IMM might impact costs to the state and local governments. The Energy Choice Amendment allows the Legislature to determine the nature of these entities and the means by which they will be established and funded, and it is impossible to know today how the Legislature might approach the task.

The fact that such entities need to be established and initially funded does not necessarily require any significant cost to government, as fees and charges assessed to market participants could potentially be obligated to secure bonds issued and repaid by an independent special purpose entity created to finance establishment of the ISO and IMM, with the proceeds from the issuance and sale of the bonds being used to establish these entities. Though such an approach is possible others might instead be chosen at the discretion of the Legislature. As the choice the Legislature could make in this regard is unknown, determining the probable effect the Energy Choice Amendment will have on state and local government costs and revenues in this regard is not possible at this time.

LIST OF APPENDICES

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APPENDIX A

DISENTANGLING DEREGULATORY TAKINGS

Susan Rose-Ackerman and Jim Rossi***

IN recent years, the United States utility industry, faced with the massive restructuring of traditional natural monopolies such as telecommunications, natural gas, and electricity,[1] has raised a novel argument in takings jurisprudence. With the onslaught of competition many United States infrastructure firms claim to have suffered

* Henry R. Luce Professor of Law and Political Science, Yale University. This Article is drawn from a paper prepared for a conference, Private Infrastructure for Development: Confronting Political and Regulatory Risks, see infra note 6. The authors wish to thank Bruce Ackerman, Steven Bank, Julie Clugage, Joseph Dodge, Larry Garvin, Timothy Irwin, Alvin Klevorick, Andrzej Rapaczynski, Mark Seidenfeld, Warrick Smith, Paul Stephan, and participants in a workshop at Yale Law School for their helpful comments on a draft. Jonathon Rodden and Allison Turnbull provided superb research assistance.

** Patricia A. Dore Associate Professor, Florida State University College of Law. Visiting Associate Professor, University of Texas School of Law, 2000–01.

[1] See, e.g., Joseph D. Kearney & Thomas W. Merrill, The Great Transformation of Regulated Industries Law, 98 Colum. L. Rev. 1323 (1998) (describing the deregulation of six core common carrier and public utility industries—railroads, airlines, trucks, telecommunications, electricity, and natural gas).

lost profits due to the past actions of government.[2] These lost revenues, the firms argue, interfere with reasonable investment-backed expectations and thus constitute a taking.[3] "Deregulatory takings" are not only used by the industry to press judicial claims against state and federal regulators, they are also peddled to policymakers in an effort to convince them to establish "transition" surcharges that consumers or new market participants will be required to pay.[4]

While United States regulators and courts struggle with the stranded cost issue, regulators and courts in developing countries face a structurally similar issue: How does a state attract foreign investment where there is some possibility that the commitments behind its current regulatory regime may change? Like deregulation in the United States, legal, political, and regulatory transitions in developing countries pose political and regulatory risks[5] that

[2] See J. Gregory Sidak & Daniel F. Spulber, Deregulatory Takings and the Regulatory Contract: The Competitive Transformation of Network Industries in the United States 8–9 (1997) ("[T]he predictable appeal that competition holds for legislators and regulators should not obscure the fact that the transition from regulated monopoly to competition, like the transition from dirty air to clean, is not free.... Electric utilities alone may face $200 billion or more in 'stranded costs' as a result of the growth of independent power producers and the advent of wholesale and retail wheeling. That is a public policy challenge at least as large as the savings and loan cleanup.") [hereinafter Sidak & Spulber, Regulatory Contract]. The same argument is also made in J. Gregory Sidak & Daniel F. Spulber, Givings, Takings, and the Fallacy of Forward-Looking Costs, 72 N.Y.U. L. Rev. 1068 (1997) [hereinafter Sidak & Spulber, Givings], and J. Gregory Sidak & Daniel F. Spulber, Deregulatory Takings and Breach of the Regulatory Contract, 71 N.Y.U. L. Rev. 851, 855 (1996) [hereinafter, Sidak & Spulber, Deregulatory Takings]. The notion of stranded costs and the legal argument for recovery is discussed further at Part II, infra. The definition of stranded costs is discussed infra at note 82.

[3] See Sidak & Spulber, Regulatory Contract, supra note 2, at 4 ("Courts will soon face a third genre of takings cases that will make the past analysis of regulatory takings seem simplistic by comparison.").

[4] According to a recent study by Moody's Investors Service, "approximately $102 billion of stranded costs are expected to be taken care of... via regulatory and legislative processes." Moody's Investors Service, Special Comment, Smoke, Mirrors & Stranded Costs: How Stranded Cost Estimates Went from North of $130 Billion Dollars to $10 Billion, at 1 (Oct. 1999); see also Robert J. Michaels, Stranded Investment Surcharges: Inequitable and Inefficient, Pub. Util. Fort., May 15, 1995, at 21 (addressing policy problems with stranded cost surcharges).

[5] Louis T. Wells, Jr., defines political and regulatory risks as threats to the profitability of a project that derive primarily from governmental action, rather than from market conditions, such as economic factors. See, e.g., Louis T. Wells, Jr., God and Fair Competition: Does the Foreign Investor Face Still Other Risks in Emerging Markets?, *in* Managing International Political Risk (Theodore H. Moran ed., 1998);

may undermine investor confidence, at great cost to those countries' economies.[6] Also, like investors in the United States utility industry, direct foreign investors in infrastructure projects in developing countries are increasingly seeking recovery of their realized and anticipated losses in domestic and international legal tribunals.[7]

In both instances—the United States stranded cost problem and the development of standards to protect direct foreign investment in developing countries—the claims for protection are novel, since traditional legal regimes do not adequately provide for the type of remedy sought. Thus, courts are in need of standards to assist them in determining when a change in regulation warrants recovery for investors. How courts fashion these standards and remedies is of great consequence. For most countries the private infrastructure

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Louis T. Wells & E.S. Gleason, Is Foreign Infrastructure Investment Still Risky?, Harv. Bus. Rev., Sept.-Oct. 1995, at 44. Similarly, Sidak and Spulber isolate the stranded cost issue as an "endogenous" change in governmental policy, separating it from "exogenous" shocks dues to changes in technology or economic conditions. Sidak & Spulber, Regulatory Contract, supra note 2, at 437.

[6] See Witold J. Henisz & Bennet A. Zelner, Political Risk and Infrastructure Investment (Aug. 1999) (paper presented at Private Infrastructure for Development: Confronting Political and Regulatory Risks, international conference sponsored by the World Bank Group and the Government of Italy, Sept. 8–10, 1999, Rome, Italy [hereinafter Private Infrastructure for Development]) (presenting evidence that reduced risks will increase investment levels, but risks are highly correlated with micro-level institutional reforms, such as overlapping veto points, an independent judiciary, and independent regulatory agencies), available at http://www.worldbank.org/html/fpd/risk/papers/henisz.pdf; Mirjam Schiffer & Beatrice Weder, Catastrophic Political Risk Versus Creeping Expropriation: What Determines Private Infrastructure Investment in Less Developed Countries? (Aug. 1999) (draft paper, Department of Economics, University of Basel, on file with the Virginia Law Review Association) (finding that the most robust indicators of private infrastructure investment are low political and electoral uncertainties, low expectations of expropriation, and a high level of political rights).

[7] Examples include Pakistan's renegotiation of contracts with power generators, Enron's Dabhol power agreement in India, and the fall of Suharto in Indonesia. See Part III, infra. With the growth of international investment, the number of disputes is proliferating across the world. For example, in Argentina the French Vivendi are pitted against the Tucuman provincial government over a water project, Houston Industries Energy is in a dispute with provincial regulators in Santiago del Estero, and international operators of the main Buenos Aires Port have charged that the government has given unfair advantages to a rival port. See Andreas Mandel-Campbell, Trade Disputes Sour Argentine Privatisation, Fin. Times (U.S. ed.), June 12, 1998, at 7; Argentina's Model Port Sell-Off Beginning to Lose Its Lustre, Fin. Times (London ed.), Mar. 3, 1998, at 8.

sector is central to broader public policy goals, including health, education, and welfare policy.[8] A failure by courts to fashion the appropriate balance between flexibility and compensation could have serious implications for current and future investment as well as for government policy.

Any commercial enterprise is subject to changes in the state's tax and regulatory laws, but these risks loom especially large for infrastructure industries. Infrastructure projects involve considerable risk for private investors because of the high levels of fixed capital and the long payback periods. Because infrastructure industries supply basic services, government is likely to remain involved in the industry in spite of a commitment to privatization and the entry of private suppliers. Thus, investors face not just ordinary commercial risk, but also risks that flow from the actions of the state itself.

Some see the relationship between the state and regulated firms as essentially contractual—describing it as a "regulatory contract" that imposes quite specific duties on the state, in a manner identical to a contract between private parties.[9] In reality, the situation is usually closer to the "relational contracts" described by Oliver Williamson[10] where many of the terms are poorly specified because of the complexity of the underlying environment and the long-term nature of the relationship.[11] In a competitive contracting environment, the risks would be divided between state and firm in a way that reflects their relative abilities to diversify and control the level of risk.[12] Diversified private businesses may be the most efficient risk-bearers in many cases because they are able to spread risk

[8] See, e.g., OECD, Universal Service Obligations in a Competitive Telecommunications Environment (1995).

[9] See Sidak & Spulber, Regulatory Contract, supra note 2, at 101 ("State public utility regulation of electric power generation, transmission, and distribution and of local telephony represents a contract between the state and the regulated company. The economic functions of the regulatory contract, as well as the legal duties and remedies associated with it, are identical to those of a contract between private parties.").

[10] Oliver E. Williamson, Transaction-Cost Economics: The Governance of Contractual Relations, 22 J.L. & Econ. 233, 238 (1979); Oliver E. Williamson, The Mechanisms of Governance 54–87 (1996) (discussing the relational contract framework).

[11] See Victor P. Goldberg, Regulation and Administered Contracts, 7 Bell J. Econ. 426, 444 (1976).

[12] See Timothy J. Brennan & James Boyd, Stranded Costs, Takings, and the Law and Economics of Implicit Contracts, 11 J. Reg. Econ. 41, 48 (1997).

among their investors and over their various enterprises.[13] In contrast, the state is likely to be best able to limit the risks that arise from its own actions. Efficient contracts are difficult to write because the entity best able to diversify is not always the same as the one best able to limit the level of risk.[14]

This Article focuses on the protections for infrastructure investors provided by the United States Constitution's Takings Clause and on the wisdom of incorporating such protections into the constitutions of other nation states. The Takings Clause is an example of a state-established background norm that limits the government's ability to undermine the profitability of private property. In the United States, this norm is an implicit term in every contract and provides a kind of guarantee against certain types of state actions. The state is required to pay compensation when it "takes" property for public use.

There is little dispute that the Takings Clause applies to outright government seizure or expropriation of physical property. But the allocation of the costs imposed by government regulatory or deregulatory activity is the subject of much heated debate. In the extreme, some argue that any action by government that negatively affects private property rights should count as a taking. Others exclude regulatory actions from the reach of the Takings Clause

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[13] Along these lines, a recent study finds that "creeping expropriation"—in the form of regulatory corruption, arbitrary changes in general rules, and general uncertainty—is less important than political risk for infrastructure investors. The credibility of the rulemaking process, however, does matter. See Schiffer & Weder, supra note 6.

[14] Infrastructure firms have a number of contractual methods of responding to the risks emanating from state action. These range from project finance to joint ventures to special tax breaks and subsidies provided by host governments. International and national bodies provide guarantees and insurance, and contracts are written so that disputes are resolved in international fora using the law of developed countries. See, e.g., Gerald T. West, Political Risk Investment Insurance: A Renaissance, J. Project Fin., Summer 1999, at 27; Nina Bubnova, Guarantees and Insurance for Reallocating and Mitigating Political and Regulatory Risks in Infrastructure Investment: Market Analysis 2–3 (Aug. 1999) (paper presented at Private Infrastructure for Development, supra note 6), available at http://www.worldbank.org/html/fpd/risk/papers/bubnova.pdf; Louis T. Wells, Private Foreign Investment in Infrastructure: Managing Noncommercial Risk 12–14 (Aug. 1999) (paper presented at Private Infrastructure for Development, supra note 6), available at http://www.worldbank.org/html/fpd/risk /papers/wells.pdf. We do not deal with these techniques here except to note that individualized contracts can either complement or undermine the constitutional provisions we discuss.

except in rare cases, such as when the state completely destroys the owner's use of his or her property. The actual state of American law cannot be reduced to a set of principles consistent with law and economics analysis. In the land use takings context, courts have done a poor job of articulating principled decisions. As United States courts evaluate the novel "deregulatory takings" claims, they should avoid taking a turn toward the ad hoc approach that characterizes much takings jurisprudence. Similarly, developing countries should carefully approach the issue of constitutional protections for direct foreign investment, applying a principled approach in balancing the protection of investors against the need for policy flexibility.

The approach we recommend distinguishes between government as purchaser and government as policymaker—a clear presumption in favor of compensation should govern in the former case, and a presumption against compensation should apply in the latter. We argue that this distinction is appropriate both under the United States Constitution and in emerging economies that wish to incorporate a property clause into their constitutions. The details of the doctrine might vary across regimes, but the basic principle seems a useful way to frame the debate.

Part I will briefly summarize United States takings jurisprudence with a focus on infrastructure industries. Land use takings cases decided by the Supreme Court over the past several decades—particularly landmark decisions in 1987, 1992, and 1994—leave the disposition of many regulatory takings cases subject to a highly unprincipled approach. By contrast, since the New Deal, utility regulation cases have been decided under a separate set of precedents that are predictable in both their reasoning and outcome. As Part II will argue, awarding compensation for the stranded costs of utilities undermines the precedential value of decisions addressing takings in utility regulation. We challenge the view that utility takings cases, especially in a deregulated environment, should be treated the same as land use takings cases. Part III will demonstrate the structural and economic similarities between United States takings law and the protection of infrastructure projects in developing countries. As in the United States, public utility firms and investors in developing countries are turning to courts to provide the stability that the political and regulatory regimes of the host governments often lack.

In Part IV, we will present a principled understanding of takings jurisprudence in the infrastructure context. Because the commercial and political-economic issues have a global reach, our framework is designed to assist United States courts as well as judges and constitutional reformers in developing countries that are trying to establish a credible legal framework for capital investment. For both deregulatory takings and direct foreign investment, courts need to be wary of the ad hoc approach that has characterized United States land use takings jurisprudence. Commentators addressing deregulatory takings focus almost exclusively on the efficiency of the government's regulatory decisions. A more complete analysis of the problem disentangles cases where the government is a purchaser of property from cases where it is a policymaker. We will seek to defend our claim that the government should be constitutionally required to pay compensation when it plays the role of buyer and be required to pay only limited compensation when its actions can be characterized as policymaking. Our conclusions and recommendations seek to strike a realistic balance between requiring investors to take account of government activities in planning their own actions and requiring the government to pay for the inputs it uses.

I. UNITED STATES TAKINGS LAW AND INFRASTRUCTURE INDUSTRIES

The Takings Clause of the United States Constitution requires government to pay compensation under certain conditions and thus limits the government's ability to impose costs on property owners. Central to the analysis are the complex questions of what firms can be said to have contracted for and what obligations the state should accept if it seeks to further investment without sacrificing political legitimacy. The key legal and policy issue is how to draw the line between the preservation of "investment-backed expectations"[15] and the preservation of government flexibility. An

[15] The phrase originated with Frank I. Michelman, Property, Utility, and Fairness: Comments on the Ethical Foundations of "Just Compensation" Law, 80 Harv. L. Rev. 1165, 1213 (1967).

economic analysis of takings law does not imply that everyone harmed by government actions should be compensated. Such a conclusion would only result from a strong normative commitment not to efficiency, but to the status-quo distribution of property rights.

A. Takings Law and Land Use

The Fifth Amendment to the United States Constitution provides that private property shall not be taken for public use without just compensation.[16] According to Justice Hugo Black, the "Fifth Amendment's guarantee . . . [i]s designed to bar Government from forcing some people alone to bear public burdens which, in all fairness and justice, should be borne by the public as a whole."[17] In implementing this design, the Supreme Court has required compensation when tangible things are taken directly by the government, but has often refused compensation where the owner merely suffers a diminution in the value of his property. Easy cases, which require compensation, occur when the government physically invades a farmer's land by building a highway through his cornfield or condemns a private individual's house site for use as a public swimming pool. Hard cases, which do not usually generate compensation, arise when a superhighway keeps a gas station intact but provides no exit ramp nearby or constructs a noisy sports stadium next to an apartment complex.[18] Once a "taking" is found, the level of compensation is to be set at "fair market value," but if the owner disputes the state's judgment on this matter, it is a court, not the market, that sets the price.[19]

[16] U.S. Const. amend. V ("[N]or shall private property be taken for public use, without just compensation."). Through the Fourteenth Amendment, the clause applies to state governments as well as the federal government. See Dolan v. City of Tigard, 512 U.S. 374, 383–84 n.5 (1994) (citing Chicago B & Q R.R. v. City of Chicago, 166 U.S. 226, 239 (1897) (extending the Takings Clause to the states)).

[17] Armstrong v. United States, 364 U.S. 40, 49 (1960).

[18] See Bruce A. Ackerman, Private Property and the Constitution 113–67 (1977) (presenting and critiquing this view); Andrea Peterson, The Takings Clause: In Search of Underlying Principles Part I—A Critique of Current Takings Clause Doctrine, 77 Cal. L. Rev. 1299, 1305–41 (1989) (arguing that the Supreme Court has been neither clear nor consistent in its analysis of the Takings Clause).

[19] See United States v. Miller, 317 U.S. 369, 374–76 (1943). Some states depart from this approach, allowing property owners to recover a portion of the gain in value at-

Compensation is denied when the complainant cannot legitimately claim to be entitled to the benefits that are lost when the government acts.[20] For example, American courts have found that individuals do not have the right to create a nuisance under common law and cannot claim compensation for laws that limit nuisances.[21] In practice, United States courts have not limited themselves to common law nuisances but take a broader view of the behavior that can be regulated without impinging on property rights.[22] Compensation questions are resolved without giving a canonical status to the private law.

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tributable to a public project. See, e.g., Department of Transp. v. Nalven, 455 So. 2d 301 (Fla. 1984); Calhoun v. State Highway Dep't, 153 S.E.2d 418 (Ga. 1967).

[20] In upholding a fee charged to Sperry Corporation for use of the Iran-United States Claims Tribunal, the Supreme Court found that "Sperry has not identified any of its property that was taken without just compensation." United States v. Sperry Corp., 493 U.S. 52, 59 (1989).

[21] As the Supreme Court has stated, "[A]ll property in this country is held under the implied obligation that the owner's use of it shall not be injurious to the community." Mugler v. Kansas, 123 U.S. 623, 665 (1887) (quoted by Justice John Paul Stevens in his opinion in Keystone Bituminous Coal Ass'n v. DeBenedictis, 480 U.S. 470, 488–89 (1987), and in his dissent in First English Evangelical Church v. County of L.A., 482 U.S. 304, 326 (1987) (Stevens, J., dissenting).

[22] See Joseph Sax, Takings and the Police Power, 74 Yale L.J. 36, 48–50 (1964). In Kansas a constitutional amendment prohibited the manufacture and sale of intoxicating liquors and thus made brewery property valueless. The Supreme Court denied a firm's claim for compensation in broad language:

> The power which the States have of prohibiting such use by individuals of their property as will be prejudicial to the health, the morals, or the safety of the public is not—and, consistently with the existence and safety of organized society, cannot be—burdened with the condition that the State must compensate such individual owners for pecuniary losses they may sustain, by reason of their not being permitted, by a noxious use of their property, to inflict injury upon the community.

Mugler, 123 U.S. at 669. Some Justices accept the broad reading of state power implied by this quotation while others would read the nuisance exception quite narrowly to accord more closely with common-law doctrine. For example, Justice Stevens quoted this passage in two recent cases, while then-Justice William H. Rehnquist argued that "[t]he nuisance exception to the taking guarantee is not coterminous with the police power itself." Penn Cent. Transp. Co. v. New York, 438 U.S. 104, 145 (1978) (Rehnquist, J., dissenting). It is instead a "narrow exception allowing the government to prevent 'a misuse or illegal use.'" *Keystone*, 480 U.S. at 512 (Rehnquist, C.J., dissenting) (quoting Curtin v. Benson, 222 U.S. 78, 86 (1911)). A similar contrast in views is evident in Nollan v. California Coastal Commission, 483 U.S. 825 (1987). Justice Antonin Scalia argued that the state had taken an "essential stick[] in the bundle of rights," id. at 831 (Scalia, J.), while Justice William J. Brennan found that the owners had no legitimate claim. See id. at 856–57 (Brennan, J., dissenting).

The Supreme Court has had several opportunities to address the regulatory takings issue in the land use context in recent years, but its jurisprudential position is far from clear. Some commentators purport to find a pattern.[23] However, the cases do not appear to represent orderly doctrinal development.[24] Since the Court's 1978 decision in *Penn Central Transportation Co. v. City of New York*,[25] the Court has approached regulatory takings as "essentially ad hoc, factual inquiries."[26] In deciding whether a regulatory taking has occurred, the Court has focused on balancing three factors: the "character of the governmental action," the extent to which the action interferes with "distinct investment backed expectations," and the degree of diminution in value.[27]

In the nineties the Court continued the trend of ad hoc balancing in the broad range of regulatory takings cases.[28] In 1992, the

[23] See, e.g., Frank Michelman, Takings, 1987, 88 Colum. L. Rev. 1600 (1988).

[24] See Susan Rose-Ackerman, Against Ad Hocery: A Comment on Michelman, 88 Colum. L. Rev. 1697 (1988) [hereinafter Rose-Ackerman, Against Ad Hocery]; Susan Rose-Ackerman, Regulatory Takings: Policy Analysis and Democratic Principles, *in* Taking Property and Just Compensation: Law and Economic Perspectives of the Takings Issue (Nicholas Mercuro ed., 1992) [hereinafter, Rose-Ackerman, Regulatory Takings]. Rose-Ackerman argues that there is no consistent theory behind the cases decided in the 1987 and 1988 terms: *Nollan*, *First English*, *Keystone*, and Hodel v. Irving, 481 U.S. 704 (1987). Pennell v. City of San Jose, 485 U.S. 1 (1988) was decided the next year. The takings cases decided in the 1990 term did not clarify Supreme Court jurisprudence on the regulatory takings issue. The first case, Preseault v. ICC, 494 U.S. 1 (1990), dealing with the status of private landholders' claims when a rail bed is used as a hiking trail, was judged not ripe for decision. The plaintiffs were required first to pursue their suit in the Court of Claims. A concurrence by three Justices, including Sandra Day O'Connor and Scalia, who both dissented in *Pennell*, argued that in determining whether a taking has occurred state law should determine the character of the property entitlement. See id. at 20–24 (O'Connor, J., concurring). The second case, *Sperry*, concerned a fee charged by the government for use of the Iran-United States Claims Tribunal that was judged a user fee, not a taking. See *Sperry*, 493 U.S. at 59. In 1992 the Supreme Court held in Lucas v. South Carolina Coastal Council, 505 U.S. 1003 (1992), that "when the owner of real property has been called upon to sacrifice *all* economically beneficial uses in the name of the common good, that is, to leave his property economically idle, he has suffered a taking." Id. at 1019. As is discussed infra, however, the *Lucas* test does not address the issue of partial takings, which is often the case in the regulatory takings context, and still requires significant ad hoc adjudication regarding the nature of the nuisance exception.

[25] 438 U.S. 104 (1978).

[26] Id. at 124.

[27] Id.

[28] For a fuller treatment of this issue that reaches the same conclusion based on earlier cases, see Peterson, supra note 18, at 1304 ("[I]t is difficult to imagine a body of

Supreme Court attempted to bring formalism and predictability to its takings jurisprudence with its decision in *Lucas v. South Carolina Coastal Council*.[29] *Lucas* holds that there is a presumption that regulatory action that totally eliminates the economic value of private property is a taking.[30] Although representing a victory for the property owner, the decision does not articulate a per se rule for partial regulatory takings cases and leaves a broad gray area where courts must struggle to adjudicate.[31] Even in total deprivation cases, the *Lucas* majority left open two broad categories of exceptions: uses of private property that contravene "existing rules or understandings," as defined in state law;[32] and the "nuisance exception," allowing for deference to government action intended to address key public health, safety, and welfare concerns.[33] Inquiries

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case law in greater doctrinal and conceptual disarray."); see also Richard A. Epstein, Takings, Exclusivity and Speech: The Legacy of *PruneYard v. Robins*, 64 U. Chi. L. Rev. 21, 21 (1997) ("The law of takings, with its ever expanding subject matter, is a sprawling affair with little intellectual coherence."). In a later article, however, Peterson argues that "takings decisions can best be explained by saying that a compensable taking occurs whenever the government intentionally forces *A* to give up her property, unless the government is seeking to prevent or punish wrongdoing by *A*." Andrea L. Peterson, The Takings Clause: In Search of Underlying Principles. Part II—Takings as Intentional Deprivations of Property Without Moral Justification, 78 Cal. L. Rev. 53, 59 (1990). She argues that the federal courts define wrongdoing by looking to "societal judgments." Id. at 86. The courts themselves have failed to supply a consistent rationale for their decisions, but she is able to infer one from an evaluation of the outcomes. Peterson's analysis is purely positive. Even if she is correct as a descriptive matter, however, we would still argue for the reformed approach outlined in this Article.

[29] 505 U.S. 1003 (1992). For criticism of *Lucas*, see William W. Fisher, III, The Trouble With *Lucas*, 45 Stan. L. Rev. 1393 (1993); Eric T. Freyfogle, The Owning and Taking of Sensitive Lands, 43 UCLA L. Rev. 77, 118–27 (1995); John A. Humbach, Evolving Thresholds of Nuisance and the Takings Clause, 18 Colum. J. Envtl. L. 1 (1993).

[30] Justice Scalia, writing for the majority, articulated that "confiscatory regulations" require compensation unless the governmental limitation somehow inhered in the title to land itself, "in the restrictions that background principles of the State's law of property and nuisance already place upon land ownership." *Lucas*, 505 U.S. at 1029.

[31] Here, the ad hoc balancing approach of *Penn Central* continues to apply. See David L. Callies, Regulatory Takings and the Supreme Court: How Perspectives on Property Rights Have Changed from *Penn Central* to *Dolan* and What State and Federal Courts Are Doing About It, 28 Stetson L. Rev. 523, 575 (1999).

[32] *Lucas*, 505 U.S. at 1027–28, 1030.

[33] See id. at 1027. Although the Court recognized the intersection of nuisance law and takings jurisprudence over a century ago, in Mugler v. Kansas, 123 U.S. 623 (1887), "the *Lucas* majority transformed the nuisance exception into a true, categorical exception to the Takings Clause." Scott R. Ferguson, The Evolution of the

regarding "existing rules and understandings," as well as the definition of "nuisance,"[34] create substantial uncertainty for lower courts, which need to define the scope of these exceptions on a case-by-case basis.[35]

In 1994, the Court handed down its decision in *Dolan v. City of Tigard*,[36] another substantial victory for the owner. *Dolan* continues and expands upon the Court's application of a due process test that would invalidate land use regulations "not substantially advanc[ing] legitimate state interests."[37] Although an earlier case had required an "essential nexus" between the dedication of property and a legitimate state interest,[38] *Dolan* demands only "rough proportionality" between the dedication and the impacts of the proposed development.[39] Taken together, *Lucas* and *Dolan* might be seen as the Court responding to prior requests for "a good dose of formalization,"[40] but the application of the cases is narrow and both cases leave substantial issues to be adjudicated. Thus, it is questionable whether the post-1987 cases have changed much in the Court's ad hoc approach; at best, they stand for a symbolic formalism of limited applicability.[41]

"Nuisance Exception" to the Just Compensation Clause: From Myth to Reality, 45 Hastings L.J. 1539, 1553 (1994).

[34] In his majority opinion for the Court, Justice Scalia noted that relevant factors in assessing a nuisance include

> the degree of harm to public lands and resources, or adjacent private property, posed by the claimant's proposed activities, the social value of the claimant's activities and their suitability to the locality in question, and the relative ease with which the alleged harm can be avoided through measures taken by the claimant and the government (or adjacent private landowners) alike....

Lucas, 505 U.S. at 1030–31. Such nuisances must be recognized under preexisting state law, see id. at 1029, and the application of nuisance principles must be "objectively reasonable." Id. at 1032 n.18.

[35] See Robert Meltz et al., The Takings Issue: Constitutional Limits on Land-Use Control and Environmental Regulation 189 (1999); Humbach, supra note 29, at 12–13.

[36] 512 U.S. 374 (1994).

[37] Agins v. City of Tiburon, 447 U.S. 255, 260 (1980).

[38] Nollan v. California Coastal Comm'n, 483 U.S. 825, 837 (1987).

[39] As Justice Rehnquist stated, the *Dolan* test goes beyond the nexus required by *Nollan*, focusing on "whether the degree of the exactions demanded... bears the required relationship to the projected impact" from the proposed development. *Dolan*, 512 U.S. at 388.

[40] Rose-Ackerman, Against Ad Hocery, supra note 24, at 1700.

[41] See Gregory S. Alexander, Ten Years of Takings, 46 J. Legal Educ. 586, 594 (1996).

By inviting additional takings claims,[42] the recent cases will ensure that the ad hoc approach continues. In fact, the approach of lower appellate courts continues to be ad hoc. Consider, for example, how lower courts are adjudicating the issue of the "relevant parcel"—the relevant increment of property for purposes of analysis under the Takings Clause. If, for example, a developer owns nine acres of land, divided into three equal but neighboring (separately purchased) parcels, and the development potential of one acre confined to a single three-acre parcel is destroyed due to government classification as a wetland, it is uncertain what the relevant parcel is. A court must assess whether the relevant parcel for takings analysis is the one acre of wetlands, the three-acre parcel containing the wetland, or the entire nine acres. In *Florida Rock Industries v. United States*,[43] the Federal Circuit reversed and remanded a lower court's finding of a taking, suggesting that the relevant property interests be construed to limit takings claims, including government actions that destroy part of the land's value to the claimant.[44] The Federal Circuit has consistently embraced an ad hoc, fact-based inquiry into the relevant parcel.[45]

The Supreme Court seems to be inordinately proud of the ad hoc nature of its takings opinions and has reiterated its support of case-by-case balancing in recent opinions. For example, Chief Justice William H. Rehnquist argues that "questions arising under the Just Compensation Clause rest on ad hoc factual inquiries, and must be decided on the facts and circumstances in each case."[46]

[42] In *Dolan* the Court stated, "We see no reason why the Takings Clause of the Fifth Amendment, as much a part of the Bill of Rights as the First Amendment or Fourth Amendment, should be relegated to the status of a poor relation . . . ." *Dolan*, 512 U.S. at 392.

[43] 18 F.3d 1560 (Fed. Cir. 1994), cert. denied, 513 U.S. 1109 (1995).

[44] See id. at 1572.

[45] See, e.g., Loveladies Harbor, Inc. v. United States, 28 F.3d 1171, 1181 (Fed. Cir. 1994), cert. denied, 120 S. Ct. 1554 (2000); Tabb Lakes, Ltd. v. United States, 10 F.3d 796 (Fed. Cir. 1993). A test using fact-specific criteria for determining the relevant parcel was articulated by the U.S. Claims Court in Ciampitti v. United States, 22 Cl. Ct. 310, 318 (1991).

[46] Keystone Bituminous Coal Ass'n v. DeBenedictis, 480 U.S. 470, 508 (1987) (Rehnquist, J., dissenting). Similar language is found in Justice Brennan's majority opinion in Andrus v. Allard, 444 U.S. 51, 65 (1979) ("There is no abstract or fixed point at which judicial intervention under the Takings Clause becomes appropriate. Formulas and factors have been developed in a variety of settings. Resolution of each

One of the only exceptions occurs in a partial dissent by Justice Antonin Scalia, attempting to articulate a theory of takings law.[47]

The Supreme Court's glorification of ad hoc balancing is impossible to reconcile with its interest in preserving investment-backed expectations,[48] especially when the investments are long lived and special purpose. To preserve investment-backed expectations, takings law should be predictable so that private individuals can confidently commit resources to capital projects. Predictability does not, of course, require compensation in all cases. It only requires that investors be able to predict what might or might not happen. As many economically oriented writers have argued, no taking can legitimately be claimed if the property owner anticipated that an uncompensated state action was possible and if this belief affected the price paid for the asset. Property values "are enjoyed under an implied limitation and must yield to the police power," according to Justice Oliver Wendell Holmes.[49] No government could or should indemnify investors against all of the hazards of business life.[50]

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case, however, ultimately calls as much for the exercise of judgment as for the application of logic.") (citations omitted).

[47] See Pennell v. City of San Jose, 485 U.S. 1, 16 (1988) (Scalia, J., concurring in part and dissenting in part).

[48] Frank Michelman's view that Takings Claims should preserve "investment-backed expectations," see Michelman, supra note 15, is supported by *Penn Central*, where the Supreme Court endorsed "interfere[nce] with distinct investment-backed expectations" as one factor in its ad hoc assessment of regulatory takings. Penn Cent. Transp. Co. v. New York, 438 U.S. 104, 124 (1978); see supra text accompanying note 27. In addition to *Penn Central*, Michelman's position has been picked up by the Supreme Court in Kaiser Aetna v. United States, 444 U.S. 164, 175 (1979). See also *Keystone*, 480 U.S. at 493, 499 (considering investment-backed expectations in analysis of potential regulatory taking).

[49] Pennsylvania Coal Co. v. Mahon, 260 U.S. 393, 413 (1922).

[50] For another example, consider the German Constitution under which the right to hold property is guaranteed but "property imposes duties" and its use shall "serve the public weal." Grundgesetz art. 14(2). Property may be taken by the state but only for a public purpose and only if compensation is paid. See Grundgesetz arts. 14, 19; see also David P. Currie, The Constitution of the Federal Republic of Germany 291–99 (1994) (summarizing German takings law); Donald P. Kommers, The Constitutional Jurisprudence of the Federal Republic of Germany 250–66 (2d ed. 1997) (discussing leading Constitutional Court Cases); A.J. van der Walt, Constitutional Property Clauses: A Comparative Analysis 121–63 (1999) (summarizing Germany's constitutional property clause). Compensation is required to avoid imposing undue sacrifices on individuals for the sake of the common good. See BVerfGE 24, 367 (1968), *in* Kommers, supra, at 250–52; see also van der Walt, supra, at 130–31 (comparing the German approach for determining when compensation is required with the Austrian

The problem of judicially created uncertainty is exacerbated by the ex post nature of court decisions. Federal judges are reluctant to decide cases until someone has "actually" been harmed. Not only are judges reluctant to articulate general principles of takings law, but they are also unwilling to make general rulings on the status of state actions under individual statutes.[51] In the field of regulatory takings, where the future direction of the law is unclear, economic actors cannot obtain a prospective ruling from the court on whether a particular law will effect a taking. They must wait until a concrete harm has occurred before the statute can be tested. In the face of this uncertainty, investors may forgo otherwise profitable activities, and thus, the current state of the law may produce an inefficiently low level of investment.[52]

If takings jurisprudence is both ad hoc and ex post, investors may have a very difficult time knowing whether a particular state action will or will not be judged a taking. Therefore, even if the menu of possible state actions is known and probabilities can be as-

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and Swiss approaches to this issue). However, because of the social obligations of property ownership, the state can impose some limitations on the use of property without having to pay compensation. Property owners do not have a right to create a public nuisance, but the noncompensable restrictions go beyond the prevention of harm to others. A range of regulatory restrictions has been found not to raise takings claims. See Currie, supra, at 294–96. Older understandings of property rights can be modified by law so long as owners had time to adjust to the new state of affairs. See BVerfGE 58, 300 (1981), *in* Kommers, supra, at 257–61; see also Van der Walt, supra, at 142 (discussing this case).

[51] Thus, in *Keystone*, Justice Stevens dismissed Justice Holmes's analysis in *Pennsylvania Coal* of the general validity of the act as an "advisory opinion." *Keystone*, 480 U.S. at 484. Justice Stevens then went on to argue that no taking had occurred under the similar Pennsylvania law at issue in *Keystone* because at the time of the lawsuit no company could actually demonstrate that it had been harmed. See id. at 495–96. The companies were asking the Court to pass on the general legitimacy of the statute, which the majority declined to do. Justice Rehnquist, in dissent, was willing to do this. He argued that in *Pennsylvania Coal* the general validity of the act "was properly drawn into question." Id. at 507 (Rehnquist, C.J., dissenting). Similarly, in *Pennell*, an association of landlords was given standing to challenge a portion of San Jose's rent control ordinance, but their claim that a taking had occurred was dismissed as "premature" because no landlord had actually suffered harm from the disputed provision. Pennel v. City of San Jose, 485 U.S. 1, 5–11 (1988). The partial dissent, in contrast, would have reached the merits of the takings claim. See id. at 16–19 (Scalia, J., concurring in part and dissenting in part).

[52] In contrast, the constitutional systems in some other countries permit constitutional courts to rule on the content of controversial doctrines in "abstract norm control" actions that do not require one to wait for the presentation of a concrete case. On the German system, see Kommers, supra note 50, at 13–14.

signed to each policy, investors will not be able to make informed choices because the Court has not given them clear standards to determine when compensation will be paid. The shifting doctrines of takings law introduce an element of uncertainty into investors' choices that has nothing to do with the underlying economics of the situation. This uncertainty creates two problems. First, investors do not know whether damages will be paid. Second, in the event damages are not paid, investors may be left bearing the costs of an uninsurable risk. The investment-backed expectations discussed in the American cases are themselves affected by the nature of takings law. To the extent that investors are risk averse, the very incoherence of the doctrine produces inefficient choices.

Investors are not the only ones adversely affected by the incoherence and unpredictability of takings law. Government officials may be affected as well since the vagueness of the doctrine may act as a force for conservatism among public officials. Risk-averse officials facing the possibility of compensation suits against their jurisdictions may restrict their activities simply because they dislike uncertainty. As Justice John Paul Stevens notes:

> It is no answer to say that "[a]fter all, if a policeman must know the Constitution, then why not a planner?" To begin with, the Court has repeatedly recognized that it itself cannot establish any objective rules to assess when a regulation becomes a taking. How then can it demand that land planners do any better?[53]

In short, the ad hoc nature of the Court's opinions is itself troubling and is impossible to reconcile with a belief in the importance of preserving investors' expectations, especially for infrastructure investments that are long lived and special purpose. To the extent that investors are risk averse, the very incoherence of judicial doctrine produces inefficient choices. American courts are interpreting a constitutional provision, justified as a way to reduce risks for investors, in a way that increases uncertainty. This is hardly a model for governments in emerging markets that are searching for a legal template.

[53] First English Evangelical Lutheran Church v. County of L.A., 482 U.S. 304, 341 n. 17 (Stevens, J., dissenting) (citations omitted).

B. Regulatory Takings in Infrastructure Industries

In infrastructure industries, compensation obviously would be required under the United States Constitution if the government expropriated the assets of a private power company or a port facility to use as a nationalized facility. Of course, nationalizations seldom occur in the United States, but requiring compensation in such cases is an easy application of existing law. Similarly, if a government sought to attract investment by offering cleared parcels of privately-owned land to investors, it would have to compensate those whose property was destroyed in the process.

In contrast, construction of a state-owned facility that competes with a private firm would be unlikely to trigger the Takings Clause.[54] The electric power projects constructed by the government-owned Tennessee Valley Authority ("TVA") are a case in point. Many private utilities (as well as coal and ice companies) challenged TVA on the ground that government-produced electricity would cause irreparable economic harm to them. Constitutional challenges against TVA were mounted, but the appellate courts rejected these challenges. Although not expressly framed as takings cases, a trial court hearing a series of challenges by nineteen utilities took the position that the utilities were threatened with future economic harm; however, the court also noted that the injury would be *damnum absque injuria* unless TVA itself were unlawful.[55]

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[54] Government competition is not as uncommon in the United States as it may seem: Many local governments provide utility services, such as electricity and cable television, to their citizens. Municipal territory expansion or outright municipalization may lead government to compete with private firms in the provision of services.

[55] The court reasoned,

> Since the United States has acquired these dam sites and constructed these dams legally, the water power, the right to convert it into electric energy, and the energy produced constitute property belonging to the United States. This electric energy may be rightfully disposed of.... While the Government, in selling property of the United States, performs many functions that would be performed in the operation of a private business trading in similar property, inasmuch as the energy sold is created at dams lawfully erected within the Federal power, the Government in performing these functions is not entering into private business. It is merely using an appropriate method of disposing of its property. The Government may sell land belonging to the United States in competition with a real estate agency, carry parcels in competition with express companies, and manage and control its thousands of square miles of national

In considering this matter on appeal, the Supreme Court reasoned,

> The local franchises, while having elements of property, confer no contractual or property right to be free of competition either from individuals, other public utility corporations, or the state or municipality granting the franchise. The grantor may preclude itself by contract from initiating or permitting such competition, but no such contractual obligation is here asserted.[56]

Competing private power projects were not compensated for their loss of business.

The interaction between the state and private infrastructure projects is not limited to the possibility of nationalization, which requires compensation, or state competition, which generally does not. Because infrastructure firms frequently have monopoly power in the markets where they operate, public regulation is a condition for such firms to operate at all.[57] But over time changes in regulatory policy can become more or less favorable to the regulated industry. This produces a set of takings law issues that cannot be characterized as either nationalization or state competition with private firms. If public regulation limits the value of someone's property, should the Takings Clause entitle the owner to obtain compensation? Conversely, if firms obtain windfall gains as a result of government action, should they be required to turn them over to the state?

In the case of infrastructure regulation, particularly of utilities, takings law challenges have produced a line of opinions that is largely distinct, in terms of both precedential value and reasoning, from other regulatory and land use takings cases. The courts treat

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> parks even as a private company. The Government has an equal right to sell hydro-electric power, lawfully created, in competition with a private utility.

Tennessee Elec. Power Co. v. TVA, 21 F. Supp. 947, 960–61 (E.D. Tenn. 1938) (citations omitted), aff'd, 306 U.S. 118 (1939).

[56] Id. at 139 (citing Charles River Bridge v. Warren Bridge, 36 U.S. (11 Pet.) 420 (1837) and other cases). For discussion of the *TVA* cases, see George D. Haimbaugh, Jr., The TVA Cases: A Quarter Century Later, 41 Ind. L.J. 197 (1965); Joseph C. Swidler & Robert H. Marquis, TVA in Court: A Study of TVA's Constitutional Litigation, 32 Iowa L. Rev. 296 (1947).

[57] Property values "are enjoyed under an implied limitation and must yield to the police power," according to Justice Holmes. Pennsylvania Coal Co. v. Mahon, 260 U.S. 393, 413 (1922).

these cases separately from other takings cases because most utilities are subject to government regulation of prices. Since the New Deal, takings cases addressing utility price regulation have been much clearer—and better justified—than the ad hoc line of opinions addressing takings in the land use regulation context.

In the early days of utility regulation at the end of the nineteenth century, the Supreme Court endorsed a "fair value" test, an approach that thrust courts into the business of valuing utility rates on substantive due process grounds.[58] Much like the current line of land use cases, these early ratemaking cases, decided largely during the *Lochner* era,[59] took an ad hoc approach to adjudicating whether government-set rates were constitutional. During that era, ratemaking controversies were arguably "[t]he most significant cases in the Court's campaign to expand the definition of property and takings."[60] The cases of the period have been described as ad hoc and unpredictable, leading to "endless litigation" and calling into question the role of courts in reviewing economic matters.[61]

The Court repudiated this activist position in the 1940s, adopting instead an "end results" test. In *Federal Power Commission v. Hope Natural Gas Co.*,[62] the Court indicated that it would focus on the result rather than the method of ratemaking. According to Justice William O. Douglas, "It is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot

[58] See Smyth v. Ames, 169 U.S. 466, 546–47 (1898).

[59] See, e.g., Morton J. Horwitz, The Transformation of American Law, 1870–1960, at 160–61 (1992); Stephen A. Siegel, Understanding the *Lochner* Era: Lessons from the Controversy over Railroad and Utility Rate Regulation, 70 Va. L. Rev. 187, 216–23 (1984); see also Robert L. Hale, Does the Ghost of *Smyth v. Ames* Still Walk?, 55 Harv. L. Rev. 1116, 1120 (1942) (arguing that ascertaining value under *Smyth* calls for analysis of several enumerated factors unrelated to value).

[60] Molly S. McUsic, The Ghost of *Lochner*: Modern Takings Doctrine and Its Impact on Economic Legislation, 76 B.U. L. Rev. 605, 616 (1996).

[61] Jim Chen, The Second Coming of *Smyth v. Ames*, 77 Tex. L. Rev. 1535, 1556–57 (1999); see also Missouri ex rel. S.W. Bell Tel. Co. v. Public Serv. Comm'n, 262 U.S. 276, 299–301 (1923) (Brandeis, J., concurring in the judgment) (noting the gradual realization that calculations rested on shifting theories); John Bauer, The Establishment and Administration of a "Prudent Investment" Rate Base, 53 Yale L.J. 495, 498–501 (1944) (noting that objections to the standard were premised on indefiniteness and difficulties of application and administration); cf. Gerard C. Henderson, Railway Valuation and the Courts (pt. 2), 33 Harv. L. Rev. 1031, 1051 (1920) (describing the fair value rule as a "juristic myth[]").

[62] 320 U.S. 591 (1944).

be said to be unjust and unreasonable, judicial inquiry... is at an end."[63] This approach is consistent with the New Deal Court's repudiation of *Lochner* and its generally deferential judicial review of economic regulations.[64]

The Supreme Court has reaffirmed this deferential approach to reviewing utility price regulation in every case decided since 1944. In *Market Street Railway v. Railroad Commission*,[65] the Court refused to require compensation where the government did not authorize full recovery of the costs of obsolete technology.[66] Later, in the *Permian Basin Rate Cases*,[67] the Court rejected a challenge to the Federal Power Commission's ability to set area-wide rates, reasoning that there is no constitutional obligation to determine individual rates on a cost-of-service basis.[68] The most recent ratemaking case considered by the Court, *Duquesne Light Co. v. Barasch*,[69] upheld a lower court's disallowance of non-"used and useful" nuclear assets and expressly reaffirmed *Hope*: "[T]oday we reaffirm these teachings of *Hope Natural Gas*."[70] Although the Court frequently does review the procedures used by regulatory bodies, it continues to be reluctant to review the economic reasoning behind regulatory decisions involving public utilities.

Three rationales, which are not as prominent in the land use context, explain the Court's deferential approach to utility ratemaking takings cases. First, the ratemaking process is self correcting. Regulators may underestimate the cost of capital in one year, but through modifications in a later year, they can correct any

[63] Id. at 602.

[64] See, e.g., Nebbia v. New York, 291 U.S. 502, 537 (1934) (signaling a shift towards more deferential judicial review, upholding regulated prices so long as they have a "reasonable relation to a proper legislative purpose, and are neither arbitrary nor discriminatory").

[65] 324 U.S. 548 (1945).

[66] See id. at 557, 564–65 (1945) (deferring to regulators' decision not to allow recovery of San Francisco street cars and bus lines valued by regulators at less than one-third the amount at which they would have been valued using historical or reproduction costs).

[67] 390 U.S. 747 (1968).

[68] See id. at 769.

[69] 488 U.S. 299 (1989).

[70] Id. at 310.

deficiency in utility earnings and revenues by adjusting cost of capital.[71] Hence, judicial review does little to increase accuracy.

Indeed, there may be significant costs to judicial review of utility ratemaking, given its complex technical nature. A second rationale for deference to regulators' decisions is that judicial review of ratemaking "impose[s] high error costs and high judicial resource costs."[72] Courts do not have nearly the same expertise or access to complex accounting and economic information as do regulators, and are more prone to embrace a "science charade" as they review complex technical matters.[73] This not only creates a high cost for courts, but the uncertainty it creates may deter regulators from innovating or slow the pace of regulatory change.

Third, the political process provides adequate protections for utilities and their investors. Utility ratemaking and other regulatory processes, which tend to be transparent and well developed, provide a forum for regulators to balance the interests of investors, firms, consumers, and the state. According to Richard Pierce,

> Detailed judicial review of ratemaking has little, if any, effect in constraining the political process.... [T]he "end result" test announced in *Hope* can be seen as a decision to allocate to the political institutions of government near total power to protect the constitutional values underlying the takings clause in the ratemaking context. This is required by the severe institutional limitations of the judiciary as a potential source of protection of those values.[74]

Since legislators and regulatory officials are more politically accountable than judges, judicial interference with regulators' decisions may thwart democratic values. Courts are best left to review the quality of regulators' decisionmaking process, not the substance of their decisions.

For these reasons, we argue that in utility regulation controversies—including controversies about deregulation—courts should

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[71] See Charles F. Phillips, Jr., The Regulation of Public Utilities: Theory and Practice 196 (3d ed. 1993).

[72] Richard J. Pierce, Jr., Public Utility Regulatory Takings: Should the Judiciary Attempt to Police the Political Institutions?, 77 Geo. L.J. 2031, 2046 (1989).

[73] E.g., Wendy E. Wagner, The Science Charade in Toxic Tort Risk Regulation, 95 Colum. L. Rev. 1613 (1995).

[74] Pierce, supra note 72, at 2046.

use the deferential approaches of cases like *Hope, Market Street Railway*, *Permian Basin*, and *Duquesne* as opposed to the more activist review approach of the recent land use takings cases. Justice Black's articulation of the purpose of regulatory takings—"to bar Government from forcing some people alone to bear public burdens which, in all fairness and justice, should be borne by the public as a whole"[75]—is not a central concern in utility regulation. As Richard Goldsmith argues, "Rate regulators do not allocate burdens between the 'public' on the one hand and the 'few' on the other," but balance "the cost of utility service between large classes of investors and consumers."[76] It would be particularly odd to invoke takings protections to the advantage of investors and the utility industry since here—unlike in the land use context—they have an overwhelming advantage in information, wealth, and political power and "boast a superior ability to bear risk and to mitigate damage from unforeseen contingencies—the precise economic attributes that justify the imposition of liability in virtually every other legal context."[77] In fact, given their institutional disadvantage in promoting political accountability, courts generally defer to regulators and avoid active involvement in the policing of utility rate regulation.[78]

This is not to suggest that the Takings Clause is without *any* application to utility price regulation. In *Duquesne*, the Court expressly recognized that there is a constitutional limit in setting utility prices: If regulators threaten the financial integrity of a utility or provide inadequate compensation to current equity owners for the risks associated with their investments, they may effectuate a taking.[79] Although lower courts occasionally raise such concerns,[80]

[75] Armstrong v. United States, 364 U.S. 40, 49 (1960).

[76] Richard Goldsmith, Utility Rates and "Takings," 10 Energy L.J. 241, 255 (1989).

[77] Chen, supra note 61, at 1558–59.

[78] See Pierce, supra note 72, at 2046.

[79] See Duquesne Light Co. v. Barasch, 488 U.S. 299, 312 (1989) ("No argument has been made that these slightly reduced rates jeopardize the financial integrity of the companies, either by leaving them insufficient operating capital or by impeding their ability to raise future capital. Nor has it been demonstrated that these rates are inadequate to compensate current equity holders for the risk associated with their investments under a modified prudent investment scheme.").

[80] See, e.g., Jersey Cent. Power & Light Co. v. Federal Energy Regulatory Comm'n, 810 F.2d 1168, 1181–82 (D.C. Cir. 1987) (reversing and remanding the Federal Energy Regulatory Commission's ("FERC") disallowance of unamortized nuclear investment

the Supreme Court has not applied these limits in the utility rate setting context, and its cases over the past fifty years do not suggest any eagerness to engage in a more activist review of utility price-setting. In fact, despite *Duquesne*'s anticipation that takings claims may legitimately be asserted against regulators' price-setting, some lower courts interpret the cases as allowing a significant public interest to justify the financial destruction of a regulated utility.[81]

However, a new issue has now arisen in the regulation of United States public utilities—widespread deregulation. As deregulation of utility industries proceeds apace, a self-correcting and relatively stable regulatory process is no longer the norm. Without such a process, stakeholders in the industry are increasingly pressing claims based on land use takings cases, threatening the certainty that has characterized this line of opinions for the past fifty years. We turn now to consider how this issue of deregulatory takings is being framed in the context of the restructuring of United States public utility markets.

II. THE STRANDED COST PROBLEM IN THE UNITED STATES

Many American infrastructure industries currently face increased competitive pressures through restructuring and deregulation. This has produced a new set of takings law claims, largely untested in United States courts. Utilities assert that deregulation has produced "stranded costs." The definition of stranded costs is by no means settled because it is a term with both legal and political implications for utilities and governments. Indeed, the term itself has a normative loading that may hinder an objective assessment of the problem. By calling costs "stranded" those who argue for compen-

from the rate base for failure to provide an explanation); id. at 1188–89 (Starr, J. concurring) (arguing that a "reasoned consideration" of investor interests requires more than a mechanical application of rules but requires consideration of what expectations exist under a regulatory compact).

[81] See Gulf State Utils. Co. v. Louisiana Pub. Serv. Comm'n, 578 So. 2d 71, 106 (La. 1991) (holding that a taking will be found only when the state "failed to consider the legitimate interests of the utility and its investors in a higher rate of return, and to weigh those interests against the competing concerns of the ratepayers"), cert. denied, 502 U.S. 1004 (1991); Ohio Edison Co. v. Public Utils. Comm'n, 589 N.E.2d 1292, 1300 n.8 (Ohio 1992) (boldly asserting that "'the Constitution no longer provides any special protection for the utility investor'") (quoting Dayton Power & Light Co. v. Public Utils. Comm'n, 447 N.E.2d 733, 740 (1983), quoting Neil N. Bernstein, Utility Rate Regulation: The Little Locomotive that Couldn't, 1970 Wash. U. L.Q. 223, 259–60).

sation imply that the costs are "shipwrecked"—that is, investors are the victims of misadventure brought about by government action. Economically, stranded costs occur when the costs to the incumbent exceed the costs to new entrants because of the actions of the state, not because of changes in technology or other exogenous economic shocks. These costs reflect the fact that some investments cannot earn a fair rate of return in the deregulated marketplace.[82]

Initial estimates of stranded costs in electrical utility deregulation in the United States ranged from $34 billion to $210 billion, according to one report.[83] Given these large estimates, pressures to provide the industry recovery of some, if not all, of these costs are obvious. The United States Energy Information Administration estimated that stranded costs could lead to an increase in bankruptcies in the industry if regulators did not address them.[84] Not

[82] Sidak and Spulber define stranded costs as the "inability of utility shareholders to secure the return of, and a competitive rate of return on, their investment." Sidak & Spulber, Regulatory Contract, supra note 2, at 29. Sidak and Spulber's definition includes operating expenditures required by regulators as well as capital investments. Brennan and Boyd identify four types of stranded costs in the electric power sector:

> 1. Undepreciated investments in power plants that are more expensive than generators available today. 2. Long-term contracts—most if not all mandated by the 1978 Public Utility Regulatory Policies Act (PURPA)—with high-priced independent generators, mostly using renewable energy technologies. 3. Generators built but not used, primarily nuclear. 4. Expenses related to "demand-side management" (DSM) and other conservation programs that, as substitutes for new plant construction, were charged to the generation side of the business.

Brennan & Boyd, supra note 12, at 45 (footnote omitted). Other definitions focus more on capital outlays and do not necessarily include other expenses. Herbert Hovenkamp defines stranded costs as "investments in specialized, durable assets that may have seemed necessary, or at least justifiable, when constructed and placed into service under a regime of prices and entry controls but that have become underutilitized or even useless under deregulation." Herbert Hovenkamp, The Takings Clause and Improvident Regulatory Bargains, 108 Yale L.J. 801, 802–03 (1999). Jim Rossi focuses on assets that are unable to recover their remaining capital costs after deregulation. See Jim Rossi, The Irony of Deregulatory Takings, 77 Tex. L. Rev. 297, 301–02 (1998).

[83] These estimates represent the after-tax discounted present value of the reduced contributions to cost recovery. See Eric Hirst & Lester Baxter, How Stranded Will Electric Utilities Be?, Pub. Util. Fort., Feb. 15, 1995, at 30–32, cited in Brennan & Boyd, supra note 12, at 45–46.

[84] See U.S. Department of Energy, Energy Information Administration, Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services

surprisingly, utilities are making vigorous policy arguments in favor of full or near-full recovery of stranded costs. A recent study suggests that utilities have used political and regulatory processes to obtain recovery in many states. Moody's Investors Service now estimates that stranded costs will total just $10 billion.[85] In 1995 they estimated these costs at $130 billion.[86] According to their estimates, $102 billion of the reduction in the total was due to regulatory and legislative relief.[87]

In recent years, the argument for stranded cost recovery has moved beyond policy to take on the rhetoric of legal entitlement, invoking the Contracts Clause and the Takings Clause of the United States Constitution. Although the cases regarding the regulation of utility prices are deferential to regulators, rate regulation is not the same as the deregulation of a formerly regulated industry where a competitive market will displace the regulator in setting prices. In such contexts, "deregulatory takings" challenges asserting interference with "investment-backed expectations" may still

and Financial Status of Electric Utilities: A Preliminary Analysis Through 2015, at xvi (1997).

[85] See Moody's Investor Service, supra note 4, at 1.

[86] See id.

[87] See id. The study is summarized in Andrew Taylor, Debate on U.S. Deregulation Hots Up, Financial Times, Survey: World Energy (London Ed.), Dec. 8, 1999, at 1. Some states are even allowing for stranded cost recovery even though they have not implemented retail competition in electricity. Florida, for example, has adopted a wait-and-see approach to retail deregulation of the electric utility industry. See Electric Restructuring: Before, During and After, Pub. Util. Fort., Nov. 15, 1999, at 26 (comments of Florida Public Service Commission chairman Joe Garcia). Although postponement of deregulation has kept the stranded cost issue off the public political agenda, regulators have quietly allowed utilities to accelerate depreciation and recovery of power plants. By the time Florida deregulates the industry, some utilities will have recovered the costs of their plants, so the stranded cost issue may not materialize. For example, Florida Power and Light has struck a deal with state regulators that allows it to accelerate $100 million a year in depreciation expenses for plants over the next three years. See Rate Deal Brightens Outlook for FPL; Utility Has Better Deal Against Competition, Sun-Sentinel, Mar. 28, 1999, at 1F, available in Lexis (noting that "FPL has been able to speed up these reported reductions of its plants through a special agreement with state regulators that was set to expire at the end of the year. The idea behind this was to reduce the company's exposure to 'stranded costs,' or money spent on power plants that won't be recovered when greater competition leaves the older assets obsolete"); see also Florida P&L Dodges a Rate Case with Deal to Cut Rates $1 Billion Over Three Years, Electric Util. Wk., Mar. 15, 1999, at 13 ("FP&L was also directed to accelerate depreciation of its nuclear and fossil assets by $100-million each year, which is down from the average of $250-million a year the PSC allowed during the past four years."), available in 1999 WL 12165227.

arise. According to J. Gregory Sidak and Daniel Spulber, who advocate a legal entitlement to recovery of stranded costs in the United States:

> The competitive transformation of local exchange telecommunications and the electric power industry raises significant questions about whether regulators should give a public utility the opportunity to recover its stranded costs. As regulators mandate the unbundling of basic network elements in local telephony or mandate wholesale and retail wheeling in the electricity industry, they introduce competitive rules that potentially deny incumbent utilities the opportunity to recover the cost of service. While competition presents incumbents with opportunities to serve customers in new ways, regulators often leave untouched the utility's preexisting incumbent burdens. Such regulatory action threatens to confiscate private property—shareholder value—for the promotion of competition, without just compensation.[88]

Those arguing for widespread compensation claim both that the government has made an implicit (if not explicit) contract with the utilities to guarantee them a competitive rate of return on their capital and that it has induced them to invest on those terms.[89] If deregulation lowers the expected value of the firm's assets, these commentators claim that a breach of contract has occurred that violates the Contracts Clause of the Constitution and may also amount to an unconstitutional taking of property.

Implicit in this deregulatory takings argument is the suggestion that courts should turn away from the deferential review of *Hope*, *Market Street Railway,* and *Duquesne* towards the more rigorous review seen in recent land use decisions—if not a complete return to *Smyth v. Ames*.[90] Sidak and Spulber's approach gives central importance to the investment-backed expectations variable in the ad hoc *Penn Central* calculus. According to them, investment-backed expectations do "all the heavy lifting in a regulatory takings case."[91] In addition, Sidak and Spulber cite in support of their argument

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88 Sidak & Spulber, Regulatory Contract, supra note 2, at 19.

89 See id.

90 See Chen, supra note 61, at 1536.

91 Sidak & Spulber, Regulatory Contract, supra note 2, at 224.

many of the Court's recent land use takings cases, including *Lucas* and *Dolan*.[92]

Given the many doctrines implicated, the legal argument for recovery of stranded costs warrants critical examination. We begin with a critique of the claim that the Contracts Clause of the United States Constitution requires compensation. We then focus on the Takings Clause. We argue that courts should not turn away from the deferential approach to review that has characterized their takings jurisprudence in the public utility context since *Hope*. However, to the extent that courts do look to land use takings cases as an analogy in evaluating deregulatory takings, under a framework presented later in the Article, we argue that only limited compensation of stranded costs is warranted.

A. The Contracts Clause

The Contracts Clause of the United States Constitution reads: "No State shall... pass any... Law impairing the Obligation of Contracts ...."[93] Although the clause is sometimes read to apply only to private contracts, a considerable body of case law and academic commentary applies the clause in some fashion to contracts between the state and private individuals and firms.[94] Even for those who would give the clause a strong reading, the protection is not absolute. The Takings Clause permits the state to condemn property it has conveyed by contract so long as it pays just compensation.[95] Richard Epstein views both the Takings Clause and the Contracts Clause as protections against rent seeking and political intrigue. According to him, if government wants to take action, it must compensate the losers unless it can justifiably invoke the police power.[96]

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[92] See id. at 250 (citing *Lucas*'s "invigoration of regulatory takings law" in support of more rigorous judicial review of state commission interconnection pricing determinations); id. at 2, 219 n.14 (citing *Lucas*); id. at 255–56 (discussing *Dolan*).

[93] U.S. Const. art. I, § 10, cl. 1.

[94] See Richard Epstein, Toward a Revitalization of the Contract Clause, 51 U. Chi. L. Rev. 703, 718–21 (1984); Sidak & Spulber, Regulatory Contract, supra note 2, at 145, 161.

[95] See Epstein, supra note 94, at 719.

[96] See Richard Epstein, Takings: Private Property and the Power of Eminent Domain 178–81 (1985).

There are two problems with this view. First, even in Epstein's own terms, it ignores the possibility that the original contract may itself have been the result of a rent-seeking deal. Perhaps a person with powerful political connections or a willingness to bribe obtained the contract from compliant officials. "White elephant" infrastructure projects are archetypal examples of rent seeking by politicians and private investors. Epstein's "police power" exception may be designed to cover this case, but he does not develop the argument fully.

Second, Epstein takes an overly narrow view of legitimate government. He wants a broad range for compensation and complains that one important case is "far too muddy in leaving open the possibility that contracts could be impaired if the impairment were 'reasonable and necessary' to accomplish some important public purpose."[97] His skepticism of government actions leads him to be *more* protective of private parties who contract with government compared with those involved in private contracts.

We express a more nuanced view. We agree that when government has made an explicit contract with a private party, the economic argnments for treating the contract as analogous to a private contract are strong. Under the Contracts Clause, the state cannot unilaterally void a particular contract unless it pays damages analogous to those faced by private parties.[98] However, the state can take actions that affect a multitude of contractual relations without being accused of "impairing the obligations of contracts." For example, it can enact a general tax increase or can change policy so that an industry faces new regulatory costs.

The application of Epstein's view to regulated public utilities is particularly problematic. Even when there is no explicit contract, some, including Sidak and Spulber,[99] have suggested that the relationship between a utility and the state is based on an implied

[97] Epstein, supra note 94, at 720 n.45; see United States Trust Co. v. New Jersey, 431 U.S. 1 (1977) (holding that the Contract Clause prohibits the retroactive repeal of a statutory covenant made between the states of New York and New Jersey to limit the ability of the Port Authority to subsidize rail passenger transportation from revenue and reserves).

[98] The exception would be the case in which the present government argues that no valid contract exists because of corruption or obvious indicia of unconscionability.

[99] See Sidak & Spulber, Regulatory Contract, supra note 2, at 101–77.

regulatory contract. Judge Kenneth Starr wrote in a concurrence to a D.C. Circuit case:

> The utility business represents a compact of sorts; a monopoly on service in a particular geographical area (coupled with state-conferred rights of eminent domain or condemnation) is granted to the utility in exchange for a regime of intensive regulation, including price regulation, quite alien to the free market. Each party to the compact gets something in the bargain. As a general rule, utility investors are provided a level of stability in earnings and value less likely to be attained in the unregulated or moderately regulated sector; in turn ratepayers are afforded universal, nondiscriminatory service and protection from monopolistic profits through political control over an economic enterprise.[100]

Borrowing from this notion, Sidak and Spulber see failure to compensate utilities for stranded costs as analogous to a breach of contract against the industry.[101]

Notwithstanding such statements, there is little legal support for viewing the relation between private firms and the regulatory agencies as analogous to private contracts. Sidak and Spulber discuss historical situations concerning bridges and public works where *explicit* contracts existed.[102] They also refer to *United States v. Winstar Corp.*,[103] a recent case in which the Supreme Court decided that the United States government could be sued for breaching contracts that the Federal Home Loan Bank Board had signed with thrifts to encourage healthy thrifts to merge with failing ones during the savings and loan crisis of the 1980s.[104] However, *Winstar* does not support their view. The ruling reaffirmed the unmistakability doctrine—that promises by the government to forgo certain types of future regulatory action will be enforced by courts

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[100] Jersey Cent. Power & Light v. Federal Energy Regulatory Comm'n, 810 F.2d 1168, 1189 (D.C. Cir. 1989) (Starr, J. concurring) (citation omitted).

[101] See Sidak & Spulber, Regulatory Contract, supra note 2, at 179 ("Given that the utility incurred its costs under the regulatory contract, the opening of the utility's market to competition—that is, the termination of the exclusivity of the utility's franchise—is a breach of a material term of that contract if not accompanied by an offsetting removal of incumbent burdens.").

[102] See id. at 140–60.

[103] 518 U.S. 839 (1996).

[104] See Sidak & Spulber, Regulatory Contract, supra note 2, at 171–77.

only if these are set forth in unmistakably unambiguous language, which a plaintiff bears the burden of proving.[105] Classic cases, such as *Charles River Bridge v. Warren Bridge*,[106] in which the Court refused to imply a protection against new competitors for a chartered bridge, advise against recovery.[107] In the general case of a regulated public utility, there is no explicit contract guaranteeing the firm a set rate of return on each specific investment. Instead, there is nothing but a history of statutes and regulatory orders. From these alone, it is difficult to infer ex post what the firm's legitimate expectations might have been.[108]

Furthermore, even if one is convinced that the relationship should be seen as contractual, it does not follow that Epstein's view of the obligations of the state must be accepted. One could make an argument that deregulation is a policy believed to have broad social benefits and that the regulated firms should not be protected from the costs of moving to this policy. One would then read the contracts as failing to protect the firms from the costs of having to face a competitive environment. In other words, contracts with the

[105] *Winstar* can hardly be said to represent a judicial consensus on the issue. Although Justices Stevens, O'Connor, and Stephen Breyer joined the portion of Justice David Souter's plurality opinion that recognizes a general exception to the unmistakability doctrine for government indemnification agreements, see id. at 871–87 (plurality opinion), five justices rejected this exception. Justices Anthony Kennedy and Clarence Thomas joined in a concurrence by Justice Scalia, see id. at 919–24 (Scalia, J., concurring), and Justice Ruth Bader Ginsburg joined in Chief Justice Rehnquist's dissent (Rehnquist, J., dissenting). See id. at 924–31. For further discussion of Winstar and its implications for government contract defenses, see Gillian Hadfield, Of Sovereignty and Contract: Damages for Breach of Contract by Government, 8 S. Cal. Interdisc. L.J. 467, 479–88 (1999); Michael P. Malloy, When You Wish Upon *Winstar*: Contract Analysis and the Future of Regulatory Action, 42 St. Louis U. L.J. 409 (1998); Joshua I. Schwartz, Assembling *Winstar*: Triumph of the Ideal of Congruence in Government Contracts Law?, 26 Pub. Cont. L.J. 481 (1997); Thomas J. Gilliam, Jr., Note, Contracting With the United States in its Role as Regulator: Striking a Bargain with an Equitable Sovereign or Capricious Siren?, 18 Miss. C. L. Rev. 247 (1997).

[106] 36 U.S. (11 Pet.) 420 (1837).

[107] For discussion of the relevance of this case to the stranded cost issue, see Hovenkamp, supra note 82, at 808–12.

[108] Under United States case law, there is a presumption that general language in statutes and regulations "is not intended to create private contractual or vested rights but merely declares a policy to be pursued until the legislature shall ordain otherwise." National R.R. Passenger Corp. v, Atchison, Topeka & Sante Fe Ry. Co., 470 U.S. 451, 466 (1985) (quoting Dodge v. Board of Educ., 302 U.S. 74, 79 (1937)).

state can be read to contain an implicit public welfare condition, including a commitment to widespread competition.

B. The Takings Claims

The takings argument might therefore seem the more plausible argument in favor of legal recovery of stranded costs. But those making the claim for deregulatory takings face several daunting obstacles.

First, as discussed above, United States takings jurisprudence has not found that regulatory actions in infrastructure industries demand compensation. Procedural guarantees and political accountability are sufficient, although those pressing for deregulatory takings also argue that this approach is in need of reform. Supporters of a legal entitlement to compensation would abandon the deferential tradition of *Hope*, *Market Street Railway*, *Permian Basin* and *Duquesne*, instead treating deregulatory takings cases as similar to land use takings. The land use cases are weak precedents, however, because unlike individual property owners, utility investors appear to be adequately protected in the political and regulatory process. It is not clear that deregulation has challenged this rationale. The Takings Clause should not be used to protect those who have had a chance to influence policy or who are in a position to anticipate future changes in policy and take them into account in their investment decisions.[109]

Second, as we argued above, there are seldom explicit contracts guaranteeing regulated firms a certain rate of return on their assets or promising to indemnify them against future changes in policy.[110] Thus, firms should have internalized these risks in making their in-

[109] A recent empirical study suggests that in another context, nuclear cost overruns, regulator disallowance of costs did not have widespread adverse reputation effects on firms' access to investment fuuds. See Thomas P. Lyon & John W. Mayo, Regulatory Opportunism and Investment Behavior: Evidence from the U.S. Electric Utility Industry (June 2000), available at http://papers.ssrn.com. Their findings suggest that disallowance of stranded costs associated with power generation will not significantly affect investors' willingness to back new transmission and distribution projects.

[110] See Hovenkamp, supra note 82, at 814 (observing that very few regulated firms have contracts with the state and that courts have interpreted the explicit language of contracts that do exist literally but have not gone further); Rossi, supra note 82, at 309 (observing that only "unmistakably unambiguous" government promises create legally binding contracts and that most utility regulation in not in this form).

vestment choices. Supreme Court opinions in ratemaking cases generally require utility owners to accept the risks of unsuccessful investments.

Third, it is not at all clear that utilities were induced to invest by eager regulators, only to be surprised when regulators changed the rules for rate recovery in mid-course. Instead, some commentators argue that firms, as well as regulators, supported high levels of investment, fully aware of the risks of less than full recovery of the costs.[111] Indeed, if firms anticipate that their costs will be reimbursed no matter what the competitive environment, they have an incentive to overinvest. Assured compensation affects the incentives for strategic behavior inherent in the relationship between the regulated firm and the regulatory agency officials.[112] One result may be to exaggerate the Averch-Johnson effect under which firms select inefficiently high capital/labor ratios.[113]

To date, no court has accepted the sweeping deregulatory takings argument advocated by the industry. Where the breach of contract claim has been raised, courts have uniformly required clear and explicit contracts as a basis for protection of the utility's interest in stranded cost recovery.[114] Outside of cases involving

[111] See Hovenkamp, supra note 82, at 825; Rossi, supra note 82, at 316. One author argues that utilities have been aware of the risks of disallowance of recovery for certain types of investments since the 1950s. See Martin B. Zimmerman, Regulatory Treatment of Abandoned Property: Incentive Effects and Policy Issues, 3 J.L. & Econ. 127, 129–31 (1988) (arguing that regulatory treatment of cancelled nuclear plants in the 1980s was similar to that afforded manufactured natural gas plants in the 1950s).

[112] See Oliver E. Williamson, Deregulatory Takings and the Breach of the Regulatory Contract: Some Precautions, 71 N.Y.U. L. Rev. 1007, 1012–14 (1996); see also Zimmerman, supra note 111, at 144 (concluding that firms subject to rate regulation "in most circumstances, will seek to continue projects regardless of the social efficiency").

[113] See Harvey Averch & Leland L. Johnson, Behavior of the Firm Under Regulatory Constraint, 52 Am. Econ. Rev. 1052 (1962); Robert J. Michaels, Stranded Investments, Stranded Intellectuals, 19 Reg. 47 (1996); Williamson, supra note 112, at 1012–14.

[114] In Energy Association v. Public Service Commission, 653 N.Y.S.2d 502 (Sup. Ct. 1996), the court rejected a utility's argument that the "failure to guarantee full recovery of stranded costs constitutes breach of contract." Id. at 513. Instead, the court held "'just and reasonable' rates do not necessarily . . . immunize utilities from the effects of competition." Id. at 514. Thus, only those utilities expressly contracting for monopolies will probably be able to have such monopolies recognized and enforced. See also Hovenkamp, supra note 82, at 811 & n.42 (citing In re Binghamton Bridge,

physical invasion for access to network wires,[115] the takings claims have been rejected by the courts.[116] Even though the courts have re-

70 U.S. (3 Wall.) 51, 82 (1865) ("enforcing an explicit monopoly provision in a corporate charter")). In another case, the Public Service Company of New Hampshire ("PSNH") had been promised by the State of New Hampshire recovery of a specific investment of $2.3 billion in a bankruptcy proceeding. PSNH successfully obtained an injunction against a New Hampshire restructuring plan that did not guarantee recovery of the costs of this investment. In reviewing the district court injunction, the U.S. Court of Appeals for the First Circuit determined that there was a likelihood of success on the merits, given the specific agreements between the utility and state and federal regulators. The court also noted that the possibility of irreparable harm from bankruptcy made issuance of a preliminary injunction appropriate. See Public Service Co. of N.H. v. Patch, 167 F.3d 15 (1st Cir. 1998). However, the First Circuit held that the district court was incorrect in its decision to issue an injunction against implementation of New Hampshire's plan for all New Hampshire utilities:

> The district court's extension of the injunction to protect all other New Hampshire electric utilities is more troublesome. Although the other utilities have joined in attacks on the Final Plan similar to those made by PSNH, it is not clear that they can assert the Contracts Clause or bankruptcy reorganization arguments that made PSNH's case so appealing to the district court. Nor is it evident that utilities are constitutionally insulated against losses that result merely from a change in rate regulation that introduces competition.

Id. at 28; see also Public Service Co. of N.H. v. Patch, 167 F.3d 29 (1st Cir. 1998), cert. denied 525 U.S. 1066 (1999) (rejecting a federal preemption claim based on the "filed rate doctrine," arguing that tariffs filed with FERC preclude New Hampshire from denying stranded cost recovery, and rejecting injunction claims by utilities that lack a clear contract guaranteeing recovery from previous bankruptcy reorganization).

115 Notions of physical invasion hold a grip on the definition of what constitutes a taking in the American legal mind. In Loretto v. Teleprompter Manhattan CATV Corp., 458 U.S. 419 (1982), the Supreme Court found that the use of a few square inches of property on the outside of a building for a cable television cable connection constituted a taking. The smallest physical invasion, according to *Loretto*, can constitute a taking. Thus, mandated open access of network facilities, such as power transmission lines, without compensation may be held to be a taking. When a physical occupation is present, some courts have required compensation for a taking in the deregulation context, although the basis for the taking is a per se physical invasion, not interference with investment-backed expectations. See Gulf Power Co. v. United States, 998 F. Supp. 1386, 1394–95 (N.D. Fla. 1998) (relying upon Sidak & Spulber to support the proposition that a permanent physical occupation of property constitutes a per se taking); GTE Southwest v. Public Util. Comm'n of Texas, 10 S.W.3d 7, 10–14 (Tex. Ct. App. 1999) (finding a taking based on *Loretto* where the Commission ordered GTE to revise its tariff to ensure reasonable, nondiscriminatory bases for decisions affecting access to customers by alternate service providers, including "the relocation of multiple demarcation points to a single point of demarcation on multi-unit premises").

116 See, e.g., In re Energy Ass'n v. Public Serv. Comm'n, 653 N.Y.S.2d 502, 515 (Sup. Ct. 1996) (rejecting a deregulatory takings argument against stranded cost recovery, stating, "The rule of *Smyth v. Ames* . . . does not prevail today."); In re Retail Wheeling Tariffs, 575 N.W.2d 808 (Mich. Ct. App. 1998) (finding that retail competition

fused to accept deregulatory takings claims, deregulatory takings lawsuits have resulted in settlements—sometimes imposing transition surcharges that will cost consumers billions[117]—and have influenced the adoption of consumer surcharges and access charges at the state and federal levels.[118] The very success of public utilities in having their interests heard at the state level is an argument against applying the Takings Clause to require compensation. Although the firms will not always win all the compensation they want, utilities are clearly an important force in state politics that are well able to raise their concerns within existing institutions and procedures.

III. POLITICAL RISK AND DIRECT FOREIGN INFRASTRUCTURE INVESTMENT IN EMERGING ECONOMIES[119]

We turn now to a very different kind of investment environment, but one that raises some of the same problems as the deregulation of electric power and telecommunications in the United States. Investing in infrastructure anywhere in the world is risky because of the high fixed costs required in most projects. In general, capital cannot simply be shipped out if the investment climate turns sour. Although risk-taking is an inevitable part of any major project, po-

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requiring utilities to provide third-party access does not constitute an unconstitutional taking); see also In re Public Serv. Elec. and Gas Co.'s Rate Unbundling, 748 A.2d 1161 (N.J. Super. Ct. App. Div. 2000) (rejecting a customer's takings claim based on the argument that stranded cost surcharges unconstitutionally impair the preexisting contract with the utility). In those rare instances where there is a specific agreement between utilities and regulators, utilities have had more success with the claim. See supra note 114.

[117] See Steve Isser & Steven A. Mitnick, Enron's Battle With PECO, Pub. Util. Fort., Mar. 1, 1998, at 38 (discussing Pennsylvania litigation over stranded costs, which raised the deregulatory takings argument and resulted in a multi-billion dollar settlement).

[118] See Chen, supra note 61, at 1542–43 (discussing how the argument has played out in the context of the Federal Communications Commission). Based in part on policy arguments similar to Sidak and Spulber's, FERC has allowed for full recovery of stranded costs in its wholesale electricity restructuring order, but only partial recovery of stranded costs in restructuring the natural gas industry. See John Burritt McArthur, The Irreconcilable Differences Between FERC's Natural Gas and Electricity Stranded Cost Treatments, 46 Buff. L. Rev. 71 (1998). Some states, such as California and Rhode Island, have provided for full recovery of stranded costs in their plans to restructure the retail electricity industry. See also supra note 87 and accompanying text.

[119] Jonathan Rodden provided research assistance on this portion of the Article.

litical risks are often a function of variables under the control of governments. Firms may invest only to find their investments "stranded" because of subsequent changes in the legal and regulatory environment. Thus, the stranded cost issue—by bringing to the fore the tension between compensation to the industry and flexibility and innovation in regulatory policy—bears structural and economic similarities to a much larger problem of the political risk of investing in emerging markets.

It is one thing to locate an analogy between conditions in the United States and abroad and quite another to recommend the importation of legal doctrines. Legal transplants are commonplace, but they are always problematic since one cannot know for sure how a legal form taken from one environment will function in another. Nevertheless, if a state wishes to attract international business investment, the borrowing of legal forms has the benefit of creating a legal environment familiar to investors from the developed world. Commercial codes have sometimes been imported wholesale from developed countries into emerging economies for this purpose.[120] Bilateral investment treaties provide a set of background conditions for all contracts between firms from the treaty states. Another option is to leave one's own laws intact and encourage investors to make their own arrangements under which the law of a developed country applies and disputes are to be settled through international arbitration. There are weaknesses inherent in all of these possibilities, not the least of which is the creation of a two-track system under which foreign investors are treated differently from domestic investors—better in some ways and worse in others. Thus it makes sense to consider alternatives that lower the risks created by public actions for all investors, domestic and foreign. In seeking to create a strong environment for foreign investment, a country's goal should *not* be to maximize foreign investment but to attract productive, competitively priced projects. This suggests that a balance needs to be struck between providing security to investors and discouraging projects that generate monopoly gains.

[120] See, e.g., Philip M. Nichols, The Viability of Transplanted Law: Kazakhstani Reception of a Transplanted Foreign Investment Code, 18 U. Pa. J. Int'l Econ. L. 1235 (1997).

The reduction of political risk is an important issue since much foreign direct investment over the last two decades has been in infrastructure industries. For example, private electric power projects are of growing importance with 140 plants under construction, 211 in operation, and 486 under development as of 1998.[121] The total value of investment in private infrastructure projects in developing countries in 1997 exceeded $100 billion.[122] Infrastructure deals cover the range of possible government/private sector relationships, including simple construction contracts; build, operate, and transfer ("BOT") projects;[123] purchases of public firms; and build, operate, and own investments operating under state regulatory authority. Behind many of these deals are power purchase agreements which are long-term agreements with the buyers of a project's service—such as a commercial purchaser of electricity—that provide funds for payment of project expenses, repayment of the project's debts, and dividends or distributions to those who hold equity in the project.

Historically, many infrastructure firms were state-owned enterprises. The move to privatize these firms and to permit private investment is occurring simultaneously with the creation of national regulatory frameworks. This trend contrasts with the situation in the United States, where private firms have always been an important factor even in monopolistic infrastructure industries. Public firms are often saddled with inefficient capital stock, and the costs of disposing of these assets are borne by the state (or the taxpayer) as part of the "restructuring" process that precedes the sale of the assets. Restructuring is often just a polite way of saying that the state will take over and liquidate loss-making portions of the firm in order to increase the value of the assets to be privatized.

[121] See The Balance of Power, Economist, June 6, 1998, at 59.

[122] See Theodore H. Moran, Political and Regulatory Risk in Infrastructure Development in Developing Countries: Introduction and Overview 7 (Aug. 1999) (paper presented at Private Infrastructure for Development, supra note 6).

[123] Under a BOT arrangement, the contractor builds the plant and then sells the power that is produced for a period of time. Once one is committed to a risky environment, more control over the environment may be preferred to less. In some cases the firm may only consider the extremes of equipment sales or a BOT project. An intermediate case where the firm accepts much of the risk and has little control over its magnitude may be the worst possible strategy. Thus the structure of the deals reflects guesses about the stability of the political regime and the legal system.

In the ideal case, the assets are sold to investors who have good information about the structure of the regulatory environment in the post-privatization world. The reality is not so simple. Regulatory structures are seldom transparent, stable, and credible, and investors complain loudly about ex post changes in the rules.[124] However, anyone with experience in the countries involved ought to predict instability in the political/regulatory environment. The business environment is risky in most emerging markets, and an investor would be foolish to ignore that fact when bidding on a privatizing firm or organizing an investment project. Finance markets already incorporate risk premia that reflect regulatory uncertainty in the United States,[125] and the same is true in emerging and developing economies where a number of private advisory services provide information on economic and political risk.[126] However, because uncertainty about the legal and policy environment in developing countries may lead to extremely high risk premia,[127] countries that wish to reduce these costs would benefit from increasing the credibility of their commitments.

A basic risk that investors fear is outright expropriation. Bilateral investment treaties and international guarantee agencies outlaw expropriation and impose sanctions.[128] In practice, the like-

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[124] See Sanford V. Berg, Priorities in Market Reform: Regulatory Structures and Performance, 7 Pac. & Asian J. Energy 89, 89 (1998), available in Lexis.

[125] See A. Lawrence Kolbe & William B. Tye, The *Duquesne* Opinion: How Much "*Hope*" Is There for Investors in Regulated Firms?, 8 Yale J. on Reg. 113, 115 (1991).

[126] For example, risks are quantified in The International Country Risk Guide ("ICRG"), created in 1980 by the editors of International Reports. See Robin L. Diamonte et al., Political Risk in Emerging and Developed Markets, Fin. Analysts J., May/June 1996, at 71, 75 ("Banks, multinational corporations, importers, and exporters, among others, use the ICRG model to determine the risks of operating in, investing in, or lending to particular countries.").

[127] Claire Hill notes that political risk differs from the other risks investors face in that it attaches to heterogeneous events and involves higher levels of uncertainty. See Claire A. Hill, How Investors React to Political Risk, 8 Duke J. Comp. & Int'l L. 283, 288 (1998).

[128] For discussion of such protections, see Giorgio Sacerdoti, The Sources and Evolution of International Legal Protection for Infrastructure Investment Confronting Political and Regulatory Risks (Aug. 1999) (paper presented at Private Infrastructure for Development, supra note 6); Thomas W. Waelde, International Treaties and Regulatory Risk: The Effectiveness of International Law Disciplines, Rules and Treaties in Reducing the Political and Regulatory Risk for Private Infrastructure Investment in Developing Countries (Aug. 1999) (paper presented at Private Infrastructure for Development, supra note 6).

lihood of expropriation has fallen dramatically in recent years, although the trend could be reversed.[129] Political and regulatory risks short of outright expropriation, however, are among the most costly to the foreign investor and are not covered by contractual provisions outlawing expropriation. The problem for government policymakers is to decide when to indemnify firms against such risks and when to treat the risks as part of the ex ante calculations of investors. These risks fall into several categories.

One risk is the introduction of local competitors into a market that the investor thought had been awarded as a monopoly franchise. Particularly in network industries, modification of franchise terms may have major implications for investors and the firm.[130] Sometimes countries have made very generous deals with incumbent firms in the process of opening their markets. For example, in early 1998 the Hong Kong Government reached an agreement with Hong Kong Telecom to terminate its exclusive license more than eight years ahead of its scheduled expiration date. In return for this deal with regulators, Hong Kong Telecom received US$866 million (HK$6.7 billion) and the right to increase local charges.[131] Although the buyout of Hong Kong Telecom's franchise may seem extrava-

[129] Outright expropriation is of diminishing importance in international business dealings. Defining an act of expropriation as a government takeover of all the firms in the same industry in the same country in the same year, expropriations reached a modern high in 1974 and 1975 and fell to single digits in 1980. Between 1987 and 1992, none took place. See Michael S. Minor, The Demise of Expropriation as an Instrument of LDC Policy, 1990–1992, J. Int'l Bus. Stud., First Quarter 1994, at 177, 178–80; Michael Minor, LDCs, TNCs and Expropriation in the 1980s, 25 The CTC Reporter 53, 53–55 (1988). Philip R. Stansbury, writing at a time when expropriation risk seemed close to zero, explains how to structure deals to minimize the risks and costs of expropriation. See Philip R. Stansbury, Planning Against Expropriation, 24 Int'l Law. 677, 677–88 (1990). His discussions suggest that expropriation is uncommon, not only because of changing perceptions of the value of state takeovers, but also because multinationals have learned how to organize their businesses to limit the assets at risk. Stansbury's proposals seem to reflect common practice in international business deals even in countries where the risk of outright expropriation is small. For example, he recommends minimizing the assets under the corporate umbrella that could be an expropriation target. See id. at 678–83.

[130] In network infrastructure industries, two issues that raise uncertainty are unbundling, or conditions on vertical integration, and third-party access to network facilities. See Pierre Guislain, The Privatization Challenge: A Strategic, Legal, and Institutional Analysis of International Experience 262 (1997).

[131] See HK Telecoms Industry Enters New Era of Competition, Asia Pulse, Apr. 1, 1998, at 1, available in Lexis.

gant,[132] it bears some similarity to the way regulators often compensate the stranded costs of utilities in the United States. The main difference seems to be that in the Hong Kong case an explicit contract did exist, and the new regime was eager to maintain continuity with the previous government by honoring its contracts.

Elsewhere, governments have not been so generous.[133] In deciding on a policy, a country needs to consider the calculations of prospective investors. Guarantees can work to attract investment, but if they are too strong, moral hazard could lead to overinvestment. A government that gives overly generous guarantees to monopolists may find itself swamped with investments that earn monopoly rents and do little to improve the country's development prospects.

A second risk is the opportunistic behavior of joint venture partners, especially when the partner is a state-owned firm or one with close political connections to the regime in power. A study by the International Finance Corporation concludes that joint ventures are likely to be fragile if they depend only on the local firm's "intimate knowledge of government affairs or familiarity with local financial markets."[134] As the authors of the study point out, this "intimate knowledge" may imply corruption or conflicts of interest between the partners.[135] According to some research, few multina-

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[132] Following this deal, Kong Telecom's profit rose by 52%. See HK$ 6.7b Compensation Lifts HK Telecom Profit by 52%, Bus. Times (Singapore), May 5, 1998, at 16, available in Lexis.

[133] The monopoly franchise of the Philippine Long Distance Telephone Company was dismantled by President Fidel Ramos, and the firm now faces rigorous new competition. See Hadi Salehi Esfahani, The Political Economy of the Telecommunications Sector in the Philippines, *in* Regulations, Institutions, and Commitment 145, 196–97 (Brian Levy & Pablo T. Spiller eds., 1996); Belltel Licence Spells 'Havoc' But May End PLDT Monopoly, Asia Pac. Telecoms Analyst, Nov. 17, 1997, at 9. Singapore has indicated that it will end Singapore Telecom's monopoly on local and international services in 2000, seven years earlier than planned. See Mark L. Clifford, Asia's Furious Phone Derby, Bus. Wk., Feb. 24, 1997, at 122. Although Singapore Telecom received some compensation for its franchise, the deal with Singapore Telecom was for substantially less than the Hong Kong deal. See Early End to HK Telecom's Monopoly Gives HK the Edge, Bus. Times (Singapore), Feb. 5, 1998, at 1, available in Lexis.

[134] Robert R. Miller et al., International Joint Ventures in Developing Countries: Happy Marriages? 23 (International Finance Corporation Discussion Paper No. 29, 1996).

[135] See id. at 19.

tionals prefer local partners because of the potential for conflicts over objectives. But many must accept them as part of the bargaining process that leads to investment.[136]

Third, a new regime may seek to void or renegotiate a contract on the grounds that it provides an unconscionable level of profits to the private firms and/or was the result of corrupt payoffs or inappropriate influence by those close to the previous rulers. Deals meant to isolate a multinational from risk may not be politically sustainable if the profits turn out to be too high. Recent examples involve projects in Pakistan, India, and Indonesia.

Pakistan attracted foreign power plant contractors by promising to buy their power at a fixed price per kilowatt hour during the 1993–96 government of former premier Benazir Bhutto. This seemed at the time a clever way to isolate foreign firms from the vagaries of local electricity demand and the politically freighted nature of electric rates. As it turned out, the price appears to provide generous profits to investors and threatens to impose a large cost on the Pakistani treasury, since the country will not be able to sell the power to consumers for the contract price.

Officials allege corruption in the original contracts signed with the Bhutto government and are seeking to renegotiate the contracts to cut the tariffs. Pakistan is using its own courts to pursue this matter, and the Supreme Court of Pakistan has barred the investors from referring one dispute to international arbitration.[137] The World Bank and the International Monetary Fund are pushing for a settlement.[138] Nawaz Sharif, the Prime Minister deposed in 1999, also had been urging a settlement to create a better foreign investment climate.[139] Under the new administration, headed by

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[136] See Stephen J. Kobrin, Testing the Bargaining Hypothesis in the Manufacturing Sector in Developing Countries, 41 Int'l Org. 609, 623–24 (1987). In Papua New Guinea, for example, the government normally exercises its option to participate in mining and petroleum projects. Sometimes the government has purchased increased shares of projects under the implicit threat of expropriation. See Papua New Guinea Investment Climate Statement for 1997, Int'l Market Insight Rep., July 15, 1997, ¶ 27, available in Lexis.

[137] See Pakistan Court Bars International Arbitration in Power Tariff Row, Agence France Presse, November 3, 1999, available in Lexis.

[138] See World Bank Energy Mission in Pakistan for Talks, Agence France Presse, Nov. 1, 1999, available in Lexis.

[139] See Fate of Hubco Rests with the IMF: Talks Start Today Over the Impending Debt Crisis in Pakistan, Which Could Prevent the Electricity Generator from Paying

General Pervez Musharraf, allegations of corruption remain in the air.[140] Nevertheless, the World Bank has succeeded in resolving some of the disputes, although allegations of corruption against investors in several large independent power projects remain points of contention.[141] One investor in a major project, for example, insists that it will not negotiate over reductions in power tariffs unless corruption charges are dropped.[142]

Similar problems arose in India concerning the Dabhol electric power project in the state of Maharashtra where Enron was the lead contractor. The contract was negotiated with one state government, and when a new political party took control, it canceled the project, arguing that corruption had produced a deal that was too favorable to the foreign investors. No corruption was proved, but the deal was eventually renegotiated in a way that permitted each side to claim victory.[143]

Its Foreign Creditors, Fin. Times, July 13, 1998, Companies & Finance Section, at 23; Pakistan Pledges to Seek Power Companies Deal, Fin. Times, August 4, 1999, Asia-Pacific Section, at 4; Sharif Orders Speedy End to Power Dispute, Fin. Times, August 14–15, 1999, Asia-Pacific Section, at 5.

[140] See Christine Hill, Power Failure, Institutional Investor, Nov. 1999, at 109.

[141] See Pakistan's IPP Disputes Resolved Except Hubco, Kapco, Asia Pulse, Nov. 22, 1999, available in Lexis; Row With IPPs Holding Up ADB Lending for Pakistan, Asia Pulse, May 3, 2000, available in Lexis; Hubco to Seek Compensation from Pakistan, Agence France Presse, June 21, 2000, available in Lexis.

[142] See Hubco Links Power Tariffs Talks to Withdrawal of Charges by Pakistan, Agence France Presse, Dec. 11, 1999, available in Lexis.

[143] A critical report from the federal government's Comptroller and Auditor General, however, casts doubt on the State of Maharashtra's claims. See Frank Gray, Enron Slammed by Aud-Gen Report, Power in Asia, May 4, 1998, available in Lexis; Comptroller and Auditor General of India Debunks Maharashtra Govt.'s Claim on Enron, The Hindu, Apr. 26, 1998, available in Lexis. One structural problem that may have influenced the terms of the original deal concerns the pricing practices of the State Electricity Boards ("SEB"). The SEBs routinely subsidize farmers and domestic power users, and as a result, most are insolvent. To bring in foreign investors the federal government provided counter-guarantees to power producers who participated in state projects. In the Dabhol case, after the contract was canceled, the federal government made it clear that it would deduct any payments made under the guarantee from funds transferred to the state the following year. Perhaps as a result of this experience, the federal government at first was unwilling to provide counter-guarantees for future deals. In August 1998, however, the federal government issued counter-guarantees for three stalled projects, but the terms are less generous than those given to Enron in 1994. The goal is to permit the projects to go forward while still giving the SEBs an incentive to reform their tariff structures. See Shekhar Hattangadi, State Willing to Renegotiate with Euron, Platt's Oilgram News, Aug. 24, 1995, at 2, available in Lexis; Uphill Task for Reformers, Fin. Times, January 21, 1998, Survey—India

With the fall of former President Suharto, the new Indonesian government is seeking to void or renegotiate a number of infrastructure contracts that gave Suharto's children and close associates ownership stakes in joint ventures with foreign companies. The contracts were awarded without open competitive bidding, and the current government argues that the terms of the contracts are overly generous to investors given the costs of comparable projects in nearby countries. Not surprisingly, the companies are complaining about breach of contract. The United States government, which supported the overthrow of Suharto and has criticized the corruption of his regime, is backing its own investors, perhaps because it had insured some of the deals.[144] Although one interim settlement has been reached,[145] other disputes between Indonesia and investors remain unresolved.[146]

The cases of Pakistan, India, and Indonesia represent complex mixtures of opportunism and outrage. Corruption may have occurred but has obviously proved difficult to document. Even if no bribes were paid, the fact that the contracts look like giveaways of state funds to outsiders makes them vulnerable to renegotiation. Our discussion of takings law as a way to create credible commitments should be read in light of a basic assumption of state legitimacy. If the state writes contracts that its citizens do not accept as fair, no formal legal requirement is likely to provide sufficient protection for foreign investors.

Other regulatory risks may be less blatant, but no less costly to investors. Regulators may modify the terms of cost-of-service regulation for privately-owned natural monopolies. They may make a transition from cost-of-service regulation to alternatives, such as price caps, benchmark regulation, or negotiated franchise agreements. As with the termination or modification of franchises, many of these regulatory changes can result in heavy costs for infrastructure projects and may influence the behaviors of investors and the firm. In Jamaica, following the transition from a franchise-based

Power Section, at 1; Guarantees Ignite Flurry of Indian Power Plant Activity, Fin. Times, August 26, 1998, World Trade Section, at 4.

[144] See Jay Solomon, Sweetheart Contracts: U.S. Is Pressing Indonesia to Honor Suharto-Era Deals, Asian Wall St. J. July 22, 1999, at 1.

[145] See Interim Deal in Indonesian Power Dispute, Fin. Times, March 10, 2000, at 10.

[146] See Indonesia Power Plant Project Could Cost Germany Millions, Deutsch Presse-Agentur, May 27, 2000, available in Lexis.

structure to commission regulation in 1962, Jamaica Telephone Company stopped all investment in infrastructure expansion. The Jamaican network was not expanded until the 1980s.[147] In some contexts, investment risks also can be influenced by decisions of regulators in non-host countries that share revenues to pay for infrastructure in telecommunications[148] or that provide fuel for the energy sector.

Obviously, the complex of problems outlined here cannot be remedied with a single instrument. Furthermore, constitutional guarantees mean little in some emerging economies where new constitutions have appeared at frequent intervals and amendments are commonplace. Nevertheless, constitutional law usually has some special status, and, at least in countries where this is so, constitutional property protections may make sense. The risk, however, is that countries will adopt a rigid solution that is interpreted by the courts in ways that severely limit democratic accountability. Reformers need to keep the dual goals of investment security and policy flexibility in balance. In the next Part of this Article we provide some general guidance that is derived from the United States experience. As should be clear from the first Part of the Article, however, we by no means recommend the wholesale adoption of United States law. Instead, each country will need to consider the factors we discuss and make its own decisions.

IV. DEVELOPING A PRINCIPLED TAKINGS JURISPRUDENCE

A constitutional takings clause provides protection for private property rights by requiring government compensation under certain conditions, and thus limits the government's ability to impose costs on property owners. A takings provision is "an attempt to find some fair balance between the forces of change and the secu-

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[147] See Esfahani, supra note 133, at 23.

[148] For example, the United States Federal Communications Commission has moved toward making foreign telecoms pay more in the long distance charges they share with United States telecom operators. Some foreign telecoms, such as Phillipine Long Distance Telephone, Hong Kong Telecom, and Indosat of Indonesia derive 19% to 46% of their profits from these payments. See Clifford, supra note 133, at 122. Developing countries receive more long distance calls than they make, adding to the impact their telecom sector will suffer as such charges are modified. See Crossed Wires in Global Telecoms, UNESCO Courier, Nov. 1, 1998, at 1, available in Lexis.

rity of established interests."[149] For us, the basic tension in articulating a consistent doctrine is between the government as purchaser and the government as policymaker. Government can affect private property owners both when it seeks to obtain resources for a public project using the power of eminent domain and when it exercises policymaking authority. A key issue for takings jurisprudence is where to draw the line between these two types of state action. We argue that in the former case, compensation should be required under a constitutional takings clause. In the latter case, it should not be required, although it may be justified in particular instances.[150] Central to our argument is the recognition that the government has sources of power independent of the market. If reformers propose a constitutional takings clause, then they must ask how strong a role it ought to play in limiting government policy. We believe that our proposed framework is consistent with the United States Constitution and also argue that it is appropriate for countries considering constitutional and regulatory reform.

The basic problem is to distinguish between situations where the state should operate under the same constraints as private market actors and other situations where it ought to be excused from these constraints. This is a question that each state needs to answer on its own. It cannot be derived from takings law doctrine standing alone but is at the heart of a nation's view of the relationship between public power and private rights. Just as a takings clause cannot solve the problems raised by an unaccountable and illegitimate state, so too it cannot determine which property entitlements are democratically legitimate and which violate underlying concepts of ownership. These issues must be faced head-on both by policymakers in emerging economies seeking to establish a rule of law and by federal judges in the United States seeking a way through the thicket of American jurisprudence. The most appropriate takings rule is a function of other features of the political/economic environment. In developing countries, attempts to create strong constitutional protections for private property must go along with

[149] Sax, supra note 22, at 48.

[150] Joseph Sax articulates a related but somewhat different view. He distinguishes between the government as market participant and the government as mediator of competing economic claims. For him, compensation would be required only in the former case where the public action benefits a government enterprise. See id. at 62–64.

reforms in the operation of the state. A state that has a strong underlying commitment to the market economy need not be overly worried about establishing sweeping constitutional protections against government actions—witness the United States' weak and unclear constitutional restraints on regulatory incursions.

Even if one accepts our basic distinction between the government as purchaser and the government as policymaker, this does not resolve all questions of when a taking should be found and how much compensation should be paid. There still remain issues that turn on the insurance function of takings law and on its impact on the fairness and political legitimacy of alternative rules. We discuss these issues at the end of this Part.

A. Government as Buyer

If the government is a purchaser, this implies that, when possible, the state ought to act like any other market participant. It should pay its employees the market wage and purchase inputs at market prices. Private actors can then ignore the fact that the government might in the future be a purchaser, since it acts just like anyone else.[151]

Under an extreme version of this view, the government could not obtain property for public use unless the seller agreed. When the government purchases a good or service in a competitive private market, the seller's consent is a condition of the purchase. When the state is trying to assemble a parcel of land for a public project, however, requiring consent would give individual property holders the power to extract excess rents. To overcome this problem, most governments have the power of eminent domain. That is, they can take property to fulfill public purposes. The uniqueness of land parcels means that this kind of taking will frequently involve real estate.

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[151] Cf. Michelman supra note 15 at 1230–32 (noting the government obligation to pay market value); see also Ackerman, supra note 18, at 52–53 (arguing that compensation is required to limit corruption and the partisan imposition of costs); Sax, supra note 22, at 64–65, 75–76 (arguing that compensation should be paid to limit unfairness and prevent individualized cost-bearing in the public interest); Saul Levmore, Just Compensation and Just Politics, 22 Conn. L. Rev. 285, 308 (1988) (arguing that market mechanisms may provide a sufficient check on the political process in this context).

When eminent domain is used, payment of compensation at market rates gives property owners the incentive to invest based on estimates about future market conditions without also having to guess the likelihood that the state will seize their assets. In other words, compensation is justified for the same reason that government is required to pay for any inputs it uses. The goal is to make private investors indifferent between whether the government or a private buyer obtains their assets. The government's demand for resources should not interfere with market tests on the margin. In short, the ex ante probability that the government will coercively take any particular piece of property is small in this first class of cases, making it appropriate for the government to imitate private market purchasers as much as possible. Compensation is required independent of any special features of the owner or the property itself. In principle, since the government is forcing a "sale" by its condemnation procedures, the owner should be compensated for any idiosyncratic value attached to the property. This is an impractical demand, however, because it would give the owner an incentive to inflate his valuation to obtain excess compensation.

Even here, we would add one caveat. If a state has an anti-monopoly law along the lines of American antitrust statutes, the government should be authorized to appropriate profits that result from monopoly power.[152] The practical problem is distinguishing between monopoly rents and the return to risk-taking. Investors in emerging or unstable markets often incur extraordinary risks. If they are unable to shift these risks to others, they should be able to earn supra-normal profits if their investments turn out to be successful. There is, however, a circularity here. Political risk may be one reason that profit rates on successful projects are so high in the

[152] See Rose-Ackerman, Against Ad Hocery, supra note 24, at 1710; Rose-Ackerman, Regulatory Takings, supra note 24, at 37. A willingness to refuse to pay compensation for monopoly rents is consistent with the United States Supreme Court's refusal to find a taking in some recent cases. The opinions are Keystone Bituminous Coal Association v. DeBenedictis, 480 U.S. 470, 496 (1987); Justice Brennan's dissent in Nollan v. California Coastal Commission, 483 U.S. 825, 854 (1987) (Brennan, J., dissenting); and Pennell v. City of San Jose, 485 U.S 1, 10–15 (1987). See also Levmore, supra note 151, at 313 & cases cited n.61. This principle is implicit in interpretations of the United States antitrust laws that give consumers a property right in competitively priced goods and services. See Reiter v. Sonotone Corp., 442 U.S. 330, 342 (1979).

first place. If so, a compensation policy that credibly reduces political risk should not be applied retroactively to reimburse firms for lost excess profits. Conversely, if the state has a good record of compensating investors for losses incurred by state actions, then the rate of return should reflect that fact, and compensation should be based on a judgment of whether monopoly profits are being earned and on whether the government was acting as a buyer or a policymaker.

B. Government as Policymaker

Government policy may change as new political groupings come to power and new information influences the policy debate. To what extent should a takings clause protect private property owners from the vagaries of government actions? We argue that this should not be an independent goal of takings law once the basic distinction between the government as buyer and the government as power-wielder has been clarified.[153] The government pays for inputs at market prices but does not guarantee investors that its own priorities will not shift over time. For example, if the government changes regulatory priorities, no compensation should be due. To the extent that the state needs to hire more lawyers and economists to staff its agencies, it ought to pay them market rates, not dragoon them into government service. However, if a new regulatory regime affects the overall profitability of an industry and changes the relative positions of firms in the industry, this should be viewed as an exercise of government power that private firms have an obligation to take into account in their own planning for the future. A regulation that is cheaper for one firm to comply with than another should not give rise to a compensation claim by the disadvantaged firm.[154]

[153] In the United States a historical analysis reveals that the takings clause was not to be "a bulwark for the maintenance of the established distribution of wealth." Sax, supra note 22, at 53.

[154] The case would be different if the government had signed an explicit contract with the private firm not to compete with it and then entered the market. In that case the firm might demand damages under breach-of-contract principles. The issue for the courts would be to decide whether to require the payment of damages or to declare the contract itself void on the ground of public policy. The issue would be one of contracts law, not takings jurisprudence.

In addition, following the lead of American doctrine, compensation should not be paid if the government action is analogous to a private action that is one of the ordinary risks of economic life. The distributive consequences produced by market pressures are a cost of maintaining the incentives needed to make markets work efficiently. For example, if the government competes with a private business by selling surplus equipment or producing electricity, this should not produce a takings claim because competitive losses do not give rise to damage claims in the private sector.[155]

Under this view, takings law should aim to provide optimal incentives to private investors, not deter opportunistic or predatory state actors. In other words, its goal is to protect private property conditional on the power of the state. It takes as given the imperfections in the government sphere and helps encourage efficient *private* investment. Suppose, for example, that a regime is predatory in the sense that rulers use their power to enact policies that provide private benefits to themselves, their families, and their close associates. If a state has this character, takings law should not insulate investors from this influence. If it does, the costs of state overreaching will simply be shifted to other groups in the population, and an inefficient level of private investment will occur. Of course, it is not only predatory states that impose costs. Democratic governments, in permitting policies to be adopted by majority votes in representative assemblies, do not contemplate that all statutes will meet with unanimous approval. The status quo has no special legitimacy except to the extent that the constitution establishes rights that cannot be violated by ordinary legislation. This fundamental feature of democratic government should not be undermined by a takings doctrine that forbids majoritarian policies.

This framework leads us to the following conclusion. If the government needs to tear down your house in order to fulfill some broader public goal, it must compensate you at market rates. How-

[155] According to Sax, the essence of property

> is not fixity at all, but fluidity. Property is the end result of a process of competition among inconsistent and contending economic values. Instead of some static and definable quantity, property really is a multitude of existing interests which are constantly interrelating with each other.... Property is thus the result of the process of competition.

Sax, supra note 22, at 61 (footnote omitted).

ever, if the government determines that a dangerous microbe can be rooted out only by burning down everyone's house, then no compensation is required, since this is a policy applied across the board. In other words, the takings law that we favor is not designed to solve the deep problems that arise from a dysfunctional and predatory state. Neither is it meant to undermine the possibility for democratic decisions that impose costs as well as benefits. Instead, if obviously inefficient state actions are a feature of the investment climate, these government policies should be taken into account by private investors. If investors were fully compensated for such losses, they would overinvest in durable capital. Takings jurisprudence should not make investors indifferent to the government's capital-destroying actions. A no-compensation rule for broad policy initiatives would encourage investors to lobby the state to refrain from its wasteful policies.

Compensation need not, in practice, equal zero, but the state should only pay compensation for investments that would have been efficient in the absence of compensation. Investors must receive a lump sum payment, not a share of the existing capital investment. Of course, we are not recommending that states be permitted to act with impunity. We are only claiming that *if* they do so, private firms ought to take this behavior into account in planning their investment strategies. Otherwise, the costs of the ill-advised state policies will be compounded by inefficient private investment decisions. If a firm expects to be fully compensated for a public policy that destroys its property, it will invest too much in the property.[156]

Even in the policymaking category there are times when the government should pay compensation if it wishes to encourage efficient private investment. Sometimes the government takes private property and does not destroy it but instead converts it to

[156] For a fuller discussion of the issue of overinvestment, see Lawrence Blume & Daniel L. Rubinfeld, Compensation for Takings: An Economic Analysis, 72 Cal. L. Rev. 569, 618–620 (1984); Lawrence Blume et al., The Taking of Land: When Should Compensation be Paid?, 77 Q. J. Econ. 71, 71–92 (1984). As Blume and Rubinfeld argue, "Whatever the exact determination of compensation, it is important that the measure be one that cannot be directly affected by the behavior of the individual investors, since any compensation measure which can be affected by private behavior will create the possibility of inefficiency due to moral hazard." Blume & Rubinfeld, supra, at 618 n.144.

its own use. In that case, full compensation should be paid, since efficiency requires the private investor to take this possibility into account. A firm should be compensated both when the state nationalizes the firm's factory and when the state passes a regulation requiring the factory to produce a certain mix of products to be sold at state-determined prices.

This analysis suggests the following resolution of the takings law controversies surrounding the deregulation of public utilities. Deregulation is clearly a policymaking activity. Thus there is a presumption against compensation. However, the government should pay for investments that it required under the old regulatory regime that were not expected to be profitable for the private firm. The most straightforward examples are the legal obligations taken on by American electrical utilities to purchase power from solar or wind sources. In those cases firms made legal commitments that were not always economically efficient, with the understanding that they would be reimbursed by the regulatory authorities.[157] If some of a firm's assets are useful to the industry as a whole—for example, the subscriber lists maintained by telephone companies—compensation should be paid to provide an incentive for firms to develop such assets.[158] United States courts should also look at the adequacy of compensation for sharing bottleneck facilities.[159] Com-

[157] See Brennan & Boyd, supra note 12, at 49–50. Some nuclear facilities may be in this category as well, although a recent paper by Lyon and Mayo, see supra note 109, casts doubt on that claim.

[158] In the United States, the Telecommunications Act of 1996 requires that new entrants pay for these benefits, although there is a good deal of controversy over the contractual mechanism established by the Act and the resulting levels of payments. See Telecommunications Act of 1996, Pub. L. No. 104-104, 110 Stat. 56 (1996). The interconnection obligations are at 47 U.S.C. § 251(c) (Supp. III 1997). Earlier Federal Communications Commission ("FCC") attempts to require local exchange carriers to interconnect were struck down by the courts as beyond the jurisdiction of the FCC. See, e.g., Bell Atlantic Telephone Co. v. FCC, 24 F.3d 1441, 1444–47 (D.C. Cir. 1994). The court in *Bell Atlantic* held that the FCC action raised takings issues. The 1996 Act required interconnection and established a negotiation and arbitration procedure to determine the payment due local telephone companies. See Duane McLaughlin, Note, FCC Jurisdiction Over Local Telephone Under the 1996 Act: Fenced Off?, 97 Colum. L. Rev. 2210, 2224–28 (1997). The Supreme Court resolved jurisdictional disputes raised under the 1996 Act in favor of the FCC in AT&T v. Iowa Utilities Board, 525 U.S. 366 (1999).

[159] In *AT&T*, the Supreme Court remanded to the Federal Communications Commission a proceeding to determine the prices at which local exchange carriers can sell network elements to their competitors.

pensation requirements should be imposed if the state requires "open access" to facilitate the deregulation of telecommunications or electric utility industries elsewhere in the world.

In general, the compensation decision ought to depend on a two-step analysis. First, can the government action be analogized to a government purchase of an input in the market? If so, compensation should be paid at "fair market value." If not—that is, if the harm to private property owners is part of a policy initiative—then compensation should depend only on the future use of the property. The aim in the latter case is to produce optimal investment decisions by private owners given some probability of government actions that will reduce (or enhance) property values. In both cases, the economic status of the owner and the magnitude of the loss should be irrelevant. We do not, of course, claim that the distinction between government as buyer and government as policymaker will always be easy to make or that a predatory state might not carry out its aims simply by buying up properties on an individual basis. Rather, we suggest that our distinction is one way to strike a balance between giving some assurance to private investors, on the one hand, and limiting the moral hazard produced by an overly broad takings clause, on the other. We do not believe that a strong property clause, taken by itself, can be an effective method of reforming a state that is otherwise illegitimate and unaccountable.

Furthermore, the framework seems consistent with the basic principles of the American Constitution. United States law, however, is not a complete model of the rule we advocate. Compensation is routinely paid in cases that fit the first model—that is, government use of the power of eminent domain to take individual land parcels. But the American courts have not clearly distinguished between government as purchaser and government as policymaker. Furthermore, United States courts have not dealt well with the moral hazard issue. Instead, they argue that if the state destroys your "thing" for whatever reason, it usually will be required to pay you for it.[160] In contrast, if it merely uses your assets without taking title to them by, for example, requiring you to comply with historical preservation standards, the state generally will

[160] See the critical analysis of this doctrine in Ackerman, supra note 18, at 130–36.

not be required to compensate you.[161] This gives owners of buildings that might in the future be declared landmarks an incentive to tear them down quickly so that the issue will not arise.[162]

C. The Insurance Issue

Under the proposed doctrine developed so far, the extent and limits of compensation are designed to influence the investment choices of private individuals and firms, but the doctrine is indifferent to the overall economic status of investors. As a general matter, we support this view with the one exception developed here. Given the uncertainty that is an inherent feature of government, the insurance branch of the efficiency analysis may be important if private insurance markets do not fill the gap. Private property owners might want to purchase insurance if they view government as an essentially random and unpredictable enterprise, at least in its impact on particular persons.[163] If the ex ante probability of being harmed is distributed broadly and if *no* compensation is paid, two different results are possible. On the one hand, if investors are risk neutral, they all rationally cut back their investments just enough to compensate for the risk of expropriation. On the other hand, if they are risk averse, the uncertainty created by the threat of harm may lead them to invest less and to hold their assets in a form that is unlikely to be affected by the public program. For international investors this may mean that they do not invest in the country at all.

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[161] See Penn Cent. Transp. Co. v. New York, 438 U.S. 104. 122–38 (1978). But see the New York State Court of Appeals decision in Seawall Assoc. v. City of New York, 542 N.E.2d 1059 (N.Y. 1989). The New York high court found that both a physical and a regulatory taking had occurred when New York City attempted to aid the homeless by requiring owners of single-room-occupancy facilities to keep them fully rented. See id at 1062–69. Exemptions and buyout provisions in the law did not overcome this finding. Although the court did not use our reasoning, the result is consistent with our framework because the city law was designed to make use of existing buildings to further a public purpose.

[162] Cf. William A. Fischel, The Economics of Zoning Laws 174 (1985) (giving an example).

[163] Cf. William A. Fischel & Perry Shapiro, Takings, Insurance, and Michelman: Comments on Economic Interpretation of "Just Compensation" Law, 17 J. Legal Stud. 269 (1988) (analyzing situations in which government actions produce demoralization costs).

At one level, the insurance rationale is simply another justification for compensation when the government is a market participant or "buyer." A free market combined with well-enforced property rights and a law criminalizing theft insures owners that no private individual can legally take their property without their consent. They can insure against floods, hurricanes, and theft, but they do not need to insure against the possibility that someone will assert an interest in their property. Because the government can exercise its eminent domain power, however, it may appear more like a hurricane than a market participant, and hence people may demand insurance if compensation is not paid. Takings law would not need to be concerned with this problem if private insurance were available, but the risks discussed here are not always insurable because of the problems of moral hazard and adverse selection.[164]

Moral hazard occurs when the existence of insurance leads the insured person to take actions that increase the probability or the magnitude of the loss. In this context, it occurs if property owners secretly lobby to have their property taken or at least do not actively oppose a policy that will produce that result. Although such lobbying is possible when the government pays compensation, the obvious budgetary consequences of such behavior will help to check abuses. Adverse selection occurs if insurance companies cannot adequately sort property owners into risk classes. If high-risk and low-risk owners are charged the same rate, low-risk owners may decide to self insure. The remaining pool of insured owners becomes riskier and premiums must rise. The remaining low-risk owners may then opt out of the pool. If the insurance companies have less information about risks than property owners, profitable insurance contracts may be impossible to write.[165] For both of these reasons, when the state acts as a purchaser of inputs, it may sometimes be a more efficient provider of such insurance through the payment of compensation than the private market.

[164] But cf. Thomas Merrill, Rent Seeking and the Compensation Principle, 80 Nw. U. L. Rev. 1561, 1581 (1987) ("[I]t is not clear why adverse selection and moral hazard are more serious problems in this area than in any other area where risks arise primarily from acts by human agents (rather than from natural disasters).").

[165] See Blume & Rubinfeld, supra note 156, at 584–99.

However, we need to consider whether compensation should be paid, not just when the government acts as a buyer, but also when it acts as a policymaker. In considering the likelihood that property owners would demand insurance, the degree of harm is a central concern, but courts must decide what standard of comparison to use.[166] A generally accepted rule of thumb is that individuals behave in a risk-averse way when a major portion of their total wealth is threatened. Because owner-occupied housing represents a large proportion of most owners' personal wealth, the insurance rationale implies that the government should compensate homeowners when it takes their houses either as a buyer or a policymaker.[167] The standard of comparison should be the individual's total wealth, not just the property "affected" by the taking.

In developing countries, one particularly perverse result of foreign investment in infrastructure has sometimes been state expropriation of private property to help the investor amass a large land parcel for development. A takings clause could require the state to pay compensation when it condemns private houses for such purposes. Takings law can then provide security to ordinary people whose houses or small businesses stand in the way of large-scale infrastructure development projects. Unfortunately, there can be a conflict here. The insurance rationale would counsel in favor of compensation for households who lose their homes to state action whether the state is a buyer or a policymaker. Yet if full compensation is paid, homeowners will have an incentive to overinvest in their properties. Thus the compensation formula should be calculated to provide some risk sharing with property owners through deductible or co-payment options and through rules that do not pay for idiosyncratic values.

The insurance rationale is much stronger for government takings of family homes than for actions that harm broadly-held corporations.[168] There are two reasons for this. First, large diversified

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166 For example, should the courts define the plaintiff's property as the coal that cannot be mined because of the regulatory statute, so that 100% of it has been taken, or as the firm's entire mining operation, so that only a small share has been lost? See Keystone Bituminous Coal Ass'n v. DeBenedictis, 480 U.S. 470 (1987).

167 See Blume & Rubinfeld, supra note 156, at 582–99 (making this argument and discussing several examples).

168 Cf. Hanoch Dagan, Takings and Distributive Justice, 85 Va. L. Rev. 741 (1999) (exploring distributive justice perspectives on takings law).

corporations ought to be risk neutral even toward relatively large losses, because shareholders and other investors can insure by holding a diversified portfolio of investments. Private firms can diversify their risks more effectively than even many wealthy individual investors and may also be in the position to exert leverage based on international ratings of country risk.[169] Second, political risk insurance is available from both public and private sources. Increasingly, private insurers are offering political risk insurance that supplements that offered by public agencies such as the World Bank Group's Multilateral Investment Guarantee Agency ("MIGA"). Insurance provided by multilateral agencies deters governmental breach of commitments since host countries risk losing certain valuable benefits if they breach.[170] Private firms also monitor the behavior of states where they have exposure and can discipline states through higher rates or denial of coverage. Thus a country with a poor risk rating might want to establish a strong takings doctrine as a warranty that it will not take advantage of investors in fixed capital.[171] This is the final issue to which we now turn.

D. Private Investment and Public Sector Opportunism

Often, constitutional property clauses are justified as a way to deter a predatory state from interfering with the development of a favorable climate for private investment. The property clause provides a warranty or guarantee that the state will indemnify investors against certain state actions. We have already argued that compensation should be paid when the state is a purchaser of inputs, and these payments may have an indirect impact on government decisionmaking. A compensation requirement can

[169] German constitutional law has reached a similar conclusion but for different reasons. See van der Walt, supra note 50, at 135–36 (discussing the issue and citing relevant cases). Focusing on the role of property in furthering personal freedom, the German Constitutional Court distinguishes between organizational landowners where no issue of personal freedom arises and individual lessees where it does.

[170] MIGA may suspend on-going credit or loan activity when it has a dispute with a host country. MIGA offers political and regulatory risk insurance up to $200 million per project and $620 million per country. See West, supra note 14, at 34.

[171] Political risk insurance can facilitate leveraging since many lending institutions that underwrite debt in project financing are also regular buyers of political risk insurance. See id.

limit government opportunism by forcing public policymakers to consider the opportunity costs of their proposed actions. Like any other purchase of inputs, policies that "take" private property would then have concrete budgetary impacts that are immediately reflected in tax bills or borrowing capacity.

We do not believe, however, that an expansive takings doctrine is a suitable tool to deter an overreaching state in the policymaking context. If public choices are the result of the competition of various groups for political benefits, powerful groups will not need a constitutionally mandated takings doctrine to preserve their interests. Conversely, a compensation requirement is unlikely to be an effective check on the power of those groups. They are still likely to be able to obtain an overall legislative package that is beneficial to them. Those who decide on government policies do not pay the compensation themselves and suffer few negative consequences from imposing costs on those with little political clout.

Thus, a state with a strong and credible takings doctrine but with no other checks on its power can still operate with a good deal of impunity. Consider, for example, a government without an independent judiciary, in which judges are beholden to the executive or legislative branch. Such a state can manipulate the takings doctrine to compensate cronies for property taken for unproductive public projects. Ordinary people suffer both because the state engages in projects that are wasteful on their own terms and because taxpayers must pay the cost of compensation. Furthermore, investors who should be taking into account the risks of government actions in planning their own investments will not do so. The citizenry is left paying for private capital investments that are not economically justified given the likelihood that the property will be taken and destroyed by the government. In short, a regime that seeks to amass private benefits for its rulers and their associates should not be encouraged to establish a strong constitutional compensation requirement unless other reforms are carried out that increase the overall accountability of the state to its citizens. A property clause can be part of a general move to a more democratic system; it should not be a stand-alone response to an uncertain investment environment.

In this context, consider again the United States Supreme Court's generally deferential approach to takings law claims in the area of public utility regulation. The general stance of United States courts fits our distinction between state as purchaser and state as policymaker, but with one additional twist. Given a democratic government whose claim to legitimacy rests on its accountability to its citizens, policies are justified if they are the result of an accountable process—legislative, administrative, or judicial. Such policies should not give rise to takings claims beyond the requirement that the state pay for inputs. Effectively, a showing that the state has established fair processes is a defense against a takings claim. Thus the adequacy of regulatory procedures provides a justification for the United States courts' refusal to find that takings have occurred in the context of public utility regulation. Courts defer to government decisions on the ground that the legislature has established fair procedures for executive actions that impose costs and benefits on individuals and firms. Rather than go into the details of individual decisions, the court evaluates the overall fairness of the process established by law and the workings of the system in practice. As we argued above, public utilities are active participants in political and administrative processes and so can hardly be seen as innocent, uninformed outsiders.[172] They are part of the political bargaining that produces regulatory policies, and if they do not obtain one hundred percent of their goals, that is hardly a reason to pay compensation.

In any state with a basically democratic structure, standard principles of administrative law could be applied to decide whether an independent takings claim should be considered in the regulatory context. A country's courts would have to decide what procedures are necessary and sufficient to void a claim for compensation. One model for reformers in other democracies is the United States Administrative Procedure Act, which provides for notice, a hearing, and a reasoned opinion.[173] Similar issues of regulatory accountability will arise in democratic developing countries

[172] See Brennan & Boyd, supra note 12, at 49–50; Pierce, supra note 72 at 2034. Especially since the 1978 passage of a federal law permitting competition, electrical utilities have been on notice that increased competition was likely. Similar inferences would seem reasonable in telecommunications, at least since the breakup of AT&T. Among the stakeholders in the industries involved, it is the private firms who seem to have disparate political power, not other concerned groups, such as residential consumers.

[173] See 5 U.S.C. §§ 551–59 (1994 & Supp. III 1997).

for infrastructure projects operating under regulatory statutes. In general, such countries need to improve the quality of their administrative processes to make them both more dependent on technical expertise and more open and transparent to the citizens and firms interested in the outcome. A takings doctrine cannot generate such developments on its own. The administrative process should be a separate focus of reform. In the absence of procedural safeguards, however, courts could impose a higher burden of proof on the state to demonstrate that it is acting as an accountable policymaker as opposed to a purchaser. The distinction between government as purchaser and government as policymaker might be influenced by the process used to determine the government's choice.

This last proposal, however, only makes sense if a government has an underlying commitment to popular sovereignty and accountable government so that the executive is likely to respond to a finding of procedural deficiency by seeking to reform the process.[174] This is unlikely to be the case in countries with undemocratic constitutions or autocratic traditions. In those cases, takings law should not be used to encourage administrative reform since the doctrine is unlikely to generate real change on its own.

As a way of understanding our skepticism about the use of takings law as a hammer to induce reform in undemocratic or weak states, consider a takings doctrine that requires the state to pay compensation when it acts as a policymaker. If takings law were to cover these cases, consistency implies a doctrine of "reverse takings." In other words, the government should claim reimbursement from individuals or firms that receive windfalls from government actions.[175] Such claims are not part of American constitutional ju-

[174] In the United States, the failure to establish fair procedures could implicate the Due Process Clause of the Constitution as well as the Takings Clause. In one recent case, the Justices split on whether a retroactive conferral of greater benefits on retired coal employees constituted a taking or violated due process. The Court struck down a 1992 law, but its majority was split between four votes for a takings violation (Rehnquist, C.J. and O'Connor, Scalia, & Thomas, JJ.), see Eastern Enterprises v. Apfel, 524 U.S. 498 (1998), and one vote for a due process violation (Kennedy, J.), see id. at 539 (Kennedy, J., concurring in the judgment and dissenting in part).

[175] See Eric Kades, Windfalls, 108 Yale L.J. 1489, 1494–501 (1999).

risprudence,[176] yet they are a logical extension of the argument that compensation should be paid when *policymaking* activities harm some groups. Of course, a windfall tax would be difficult to administer since it would require government to distinguish between fairly and unfairly earned profits, impose high administrative costs, introduce the possibility of government mistakes, and raise investor uncertainty. The principle, however, is clear. For the reasons outlined above, we do not support this extension of takings law either in developed countries such as the United States or in developing countries with weak legal and political institutions. Rather than set up conditions that restrict government actions to those that benefit all property owners, we believe that governments need the flexibility to set policies that impose both benefits and costs. Those dissatisfied with the outcome should resort to the political process. If the political process is unresponsive, this is a troubling result, but it cannot be remedied through the quick fix of requiring compensation for all state-administered costs.

CONCLUSION

We have outlined what seems to us to be a reasonable constitutional takings doctrine that could be applied both within and outside of the American context. Whenever the government acts as the buyer of a particular asset, it should pay compensation at "fair market value." The courts would be the final arbiter of this value based on data from private market activity. When the goverument is best characterized as a policymaker, compensation should not be the general rule. Government policies that influence market rates of return would not give rise to takings clainns unless the government plans to use the private property in its existing form or unless risk-averse individuals would demand insurance that is unavailable in the private market. The doctrine thus balances some certainty for investors against the preservation of government policy flexibility. The government should pay compensation whenever it takes resources as part of the process of producing public goods and services. However, there would be a rebuttable presumption against

[176] But see Dolan v. City of Tigard, 512 U.S. 374, 399–400 (Stevens, J., dissenting) (suggesting that regulatory givings should be factored into the takings equation).

compensation for losses connected with the overall implementation of a public policy—however misguided or predatory.

The United States provides an illustration of a highly developed country whose constitution leaves open a wide range of regulatory and policy options. We do not recommend adoption of all of the details of the United States system, but it should reassure countries that flexible rules can be consistent with growth if the government is otherwise viewed as accountable and legitimate. In the American context, federal court review of public utility deregulation should not depart from the distinct line of cases addressing public utility price regulation. These cases suggest deference to regulators' decisions regarding compensation, given the democratic political process behind regulatory reform and the relative wealth and power of investors claiming injury. In our view, the courts should treat the deregulation of public utilities as an exercise of government policymaking authority that does not require compensation of "stranded costs" under the United States Constitution. The only exception would be for clearly uneconomic investments required by government policy objectives, such as the encouragement of alternative energy sources.

In countries with well-established democracies, a demonstration that the administrative structure was not fair and transparent could generate a claim for compensation under regulatory laws. We would only recommend this extension of takings law in the small number of countries where it is plausible to think that such claims will help generate reform. Such subtleties are likely to be beyond the capacity of most countries' courts and to provide only weak incentives for reform in predatory states. Regimes with a strong commitment to reform should not put their energies into refining a takings doctrine beyond a basic rule requiring compensation for inputs. Takings law is a weak tool for protecting property rights in infrastructure under changing political conditions. Reformers should instead focus on more fundamental weaknesses in political institutions and should promote the enforcement of contracts, including those to which the state is a party.

Officials in developing countries who are eager for foreign investment need to look far enough ahead to ask if the generous terms they are offering to investors will backfire in the future when citizens perceive the costs they must bear. This concern ought to temper the officials' support of either very strong guarantees of compensation for future state actions or of contract terms that leave too little flexibility to the state to respond to future conditions. In the privatization of infrastructure, this may mean that a country accepts some reduction in the sales prices of public firms in return for the preservation of policy options. Property rights protection will not aid growth if it encourages inefficient levels and types of investment. Developing countries should be wary of incorporating too sweeping a set of protections into constitutions, individual contracts, or investment treaties, especially if they are still in the process of developing effective state institutions.

* * *

Schenker, Pamela

From: Susan Clark <sclark@radeylaw.com>
Sent: Monday, March 04, 2019 1:05 PM
To: Schenker, Pamela
Subject: Article mentioned by John Reed this morning

Pam,

Below is the article John Reed mentioned this morning about Pennsylvania finding customers were paying more by switching to competitive suppliers.

Susan

Pennsylvania utility regulators are putting new limits on competitive electricity plans available to some low-income customers in FirstEnergy Corp.'s service regions after regulators found that some of those customers paid more by switching to a competitive supplier.

The unrestricted shopping cost ratepayers millions more than if they had just stayed on the utilities' default plans, regulators found.

Sixty-five percent of the customers in FirstEnergy's four Pennsylvania utilities' low-income assistance programs who signed up with a competitive supplier between 2013 and 2018 ended up in that situation.

The competitive plans cost the customer assistance programs and their participants $18.3 million more over a five-year period than the utilities' standard "price to compare," even after factoring in plans that saved ratepayers money.

Nearly $11 million of the excess costs came from the West Penn Power territory, which includes parts of 23 counties, including much of southwestern Pennsylvania, according to case records.

The higher costs harm both low-income customers who participate in the programs and general ratepayers who subsidize them, the Pennsylvania Public Utility Commission said Thursday.

Customer assistance programs offer discounted monthly bills for low-income customers who would struggle to make full-price payments on time. They also establish a path for forgiveness of past overdue balances.

Eligible customers in Akron, Ohio-based FirstEnergy's Pennsylvania programs have a gross household income at or below 150 percent of the federal poverty guidelines - $18,735 this year for a single-person household and $38,625 for a family of four.

There were about 66,000 customers in the four utilities' assistance programs in 2017, according to case records, and about 22,000 of them got electricity from a competitive supplier at some point that year.

But when customers in those programs sign up for contracts with higher rates, they are likely to exhaust their benefits and end up with charges they often can't pay, the utility commission said.

The problem is with how electricity products are marketed, said Patrick Cicero, executive director of the Pennsylvania Utility Law Project.

"It is not as if low-income customers are necessarily going out, educating themselves about the competitive market and affirmatively choosing a higher price," he said. "It is that they are often marketed to and then stuck into a higher-price contract."

Some plans offer low, short-term teaser rates that transition to higher or variable rates if the customer doesn't opt out, he said.

Customers are often approached through door-to-door sales or telemarketing, and electric bills are difficult to decipher.

The costs of the uncollectible payments are then passed on to the utility's other residential customers through higher base rates or surcharges.

The PUC on Thursday ordered FirstEnergy's Pennsylvania utilities - West Penn Power, Penn Power, Met-Ed and Penelec - to implement a program by June 1 limiting shopping by participants in their customer assistance programs to plans that offer rates at or below the utilities' default prices throughout the length of a contract.

Eligible electric plans also won't be able charge the participants early termination, cancellation or other add-on fees.

The commission issued a broader order on Thursday asking for comment on a proposed policy that would eventually apply similar restrictions to customer assistance programs offered by all electric utilities in the state when their default service plans come up for review.

Mary Long, the administrative law judge who who reviewed the FirstEnergy programs last year, said, "None of the $18.3 million in additional [customer assistance program] costs - which translates into $3.79 million more per year - are used to promote universal service goals under the Choice Act to assist low-income customers to better meet their home energy needs."

Comments on the utility commission's proposed policy change will be due 45 days after it is published in the Pennsylvania Bulletin.

Laura Legere: llegere@post-gazette.com.