THE REGULATORY ENVIRONMENT AND INDUSTRIAL RESTRUCTURING: THE CASE OF U.S. ELECTRIC POWER

by

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Abstract

This study addresses the following question: how do overlaid state and federal jurisdictions, combined with the unique technological and regulatory characteristics of the U.S. electricity industry, impact restructuring? A realist process of conceptualization invokes several levels of abstraction. French regulation theory operates at a high level, federalism at an intermediate level, and “real” regulation at a low level. Realism gives way to pragmatism at the low level of abstraction. A methodology of combining realism at high and intermediate levels of abstraction with pragmatism at low levels of abstraction is useful for geographers examining regulation at various scales. In general, borrowing from legal theory as it relates to “real” regulation injects the philosophy of pragmatism at institutional scales, which frees the researcher to embrace the complexities of the regulatory process.

The analysis indicates the following: (1) with regulatory and technological change, as the national production and delivery systems become more flexible and horizontally integrated across multi-state areas, federal market design and central regulatory oversight become increasingly relevant. (2) Decentralized production and pricing are important for reducing market volatility, providing reliable price signals for capital investment, and promoting conservation in times of shortage. The combined result is one of centripetal forces influencing the mode of regulation, while centrifugal forces influence patterns of capital accumulation.

A “regional transmission organization” (RTO) with central governance and a multi-state market will accommodate this combination of centripetal and centrifugal

forces and the associated changes in regulation and patterns of accumulation. An RTO is a "place" where discursive practices, operating through various institutions, are assuming structure as a new institutional space. Place is a process, not an object; and discursive practices will continue to influence, and be influenced by, a maturing RTO structure and its associated governance system.

Legacy regulation and patterns of accumulation impact emerging RTO structures, and policymakers must maintain a balance between federalism and regionalism. A strong relational contract among state institutions, federal institutions, and industry participants will produce a governance system that advances RTO formation. Simultaneously, policymakers can initiate processes that promote gradual RTO harmonization and integration, preferably through the work of market forces.

Chapter One: Introduction

In a shift from government regulation toward markets, various U.S. industries are restructuring. Examples include physical-network, distributed-services industries historically regulated as natural monopolies, including telecommunications, natural gas, and electricity. For each of these industries, restructuring began in the 1970s and proceeded along a unique path. Electricity restructuring advanced slowly until promulgation of the federal Energy Policy Act (EPAct) of 1992, which spurred substantial regulatory reform or "deregulation" at both the state and federal levels.

The decade following EPAct arguably constitutes the "first wave" of U.S. electricity restructuring, ending dramatically with the California crisis of 2000 and 2001, the December 2001 bankruptcy of the Enron Corporation, and the northeast blackout of August 2003. In California, deregulation produced shortages, price spikes, market manipulation, and rolling blackouts. With Enron, alleged fraud and lax federal oversight prompted a corporate implosion, followed by a collapse of the electricity-trading and non-utility "merchant" production sectors. Lastly, the "Blackout of 2003" was the largest in U.S. history, and emerged as "strike three" for the existing mode of deregulation.

Despite California, Enron, and the Blackout, electricity restructuring will move forward, but within substantially different market and regulatory environments *(Cudahy 2001, Duane 2002, Tomain 2002)*. In effect, the "rules" of U.S. electricity restructuring, while always fluid, have reached an inflection point. This study examines state and federal deregulation of the U.S. electricity industry, emphasizing the processes of restructuring within the dual regulatory framework. The broad question to be addressed is the following: how do overlaid state and federal jurisdictions, combined with the unique technological and regulatory characteristics of the U.S. electricity industry, impact restructuring? The motivation for the study at this juncture is two-fold. First, it will help illuminate the ongoing path of U.S. electricity restructuring by examining recent market and regulatory failures and corrections. Second, it will help clarify the respective roles of state and federal institutions at a time of obscure and shifting federalist boundaries.

Under the U.S. federalist system, state and federal policymaking occur within a fluid context of administrative law and politics. Federalism is a dynamic process and the most geographically expressive form of government *(Dikshit 1971, 97)*. In the U.S. electricity industry, federalism and the regulatory legacy have resulted in overlapping operating and regulatory environments, with state regulatory agencies primarily influencing intrastate production and delivery, and federal regulatory agencies primarily influencing interstate production and delivery. With deregulation, state agencies primarily influence retail markets while federal agencies primarily influence wholesale markets.

In the study of industrial restructuring, geographers often draw upon the French regulation school of political economy *(Aglietta 1987, Lipietz 1987, Boyer 1990)*, which seeks to explain the structure of capitalist economies and how they change over time. Like proponents of evolutionary and institutional economics, Regulationists believe that economic development is largely path-dependent, and the shifting requirements of capitalist production are shaped by historically contingent economic and social mechanisms. Rather than study theoretical and non-existent “perfect” markets, Regulationists attempt to explain actual capitalist economies.

French regulation theory has two core concepts: (1) "modes of regulation," a meso concept; and (2) "regimes of capital accumulation," a macro concept *(Jessop 1997, 311)*. The French regulation school credits the mode of regulation, rather than market equilibrium, as the organizing force within capitalism. In theory, the mode of regulation strives to balance production and consumption to ensure the continued reproduction of capitalism. An extended period of stability and growth, called a regime of capital accumulation, is believed to culminate in a "crisis" of accumulation. Each uniquely organized "long wave" of economic expansion and contraction ends in structural crisis and instability, with balance no longer achieved through the existing mode of regulation. A new period of stability arises only when successful new ways of organizing production and consumption, combined with an effective new mode of regulation, are found *(Jessop 1997, 288-95)*.

"Flexible" accumulation supposes a current regime of capital accumulation based on new sectors of production, new ways of providing services, new markets, and increased rates of innovation. This is often labeled "post-Fordism," indicating a break from the rigidities of the classical Fordist regime of accumulation. Fordism extended from roughly the end of the Great Depression through the 1970s and was characterized by vertically integrated production and internal economies of scale, typical of the U.S. electricity industry during that period. In contrast, post-Fordism encourages external economies through processes of vertical de-integration and flexible capital accumulation *(Piore and Sabel 1984; Harvey 1988, 1990; Scott 1988; Phelps 1992)*. According to the French regulation school, an emerging mode of regulation accompanies the emerging economics of flexible accumulation *(Moulaert and Swyngedouw 1989; Dunford 1990; Jessop 1990, 1995; Tickell and Peck 1992; Goodwin and Painter 1996).*

"Regulation" within the French regulation school includes both government and non-government regulation. But in some industries, including the U.S. electricity industry, the influence of government institutions is so pervasive as to reflect the regulatory environment as a whole. Increasingly, Regulationists are interested in the relationship between government and governance where "governance" denotes various mechanisms of coordination including networks, public-private partnerships, strategic alliances, and relational contracting. During periods of stability, governance operates within parameters defined by institutionalized structural forms, while during periods of structural crisis governance is experimental and chaotic. An emphasis on the government-governance relationship promotes contextual analysis of various shifts in economic governance, including deregulation. It also (a) provides a practical complement to an early French-regulation emphasis on basic structural forms, (b) expands regulation theory into studies of specific economic sectors and local-regional modes of regulation, and (c) builds further conceptual links to the new institutional and industrial economics, including transaction-costs analysis *(Jessop 1997, 300-02).*

Within geography, MacLeod *(1997, 533-45)* identifies three interrelated French regulation research themes: (1) the regulatory process and its discursive nature, (2) political regulation and the state, and (3) spatial scale and geographies of regulation. First, rather than being fixed, regulation is in constant flux, with participants struggling for representation through political discourse. Second, the state as institutional actor and regulatory agent functions within a political-economic framework of state strategy.

Third, regulation theory helps explain the changing space-economy of flexible capital accumulation *(Piore and Sabel 1984; Harvey 1988, 1990; Scott 1988; Phelps 1992).*

Geographers have applied elements of French regulation theory in the study of flexible production systems, agglomeration, and “new industrial spaces” *(Scott 1988, Gertler 1992, Scott and Storper 1992).* However, an explicit recognition of the mode of regulation and its relationship with industrial restructuring is largely absent *(Jessop 1990, 1995; Tickell and Peck 1992).* Despite that “[r]egulation theory provides the dynamism that is otherwise lacking within the microeconomic analysis of externalization and agglomeration” *(Phelps 1992, 39)*, the regulatory environment is often overlooked or recognized merely as a fixed backdrop.

In recent years, various U.K. geographers have applied French regulation theory to the study of “new institutional spaces” where the focus is upon the identification of, and causal forces behind, the emerging mode of regulation. Drawing upon the Thatcherist experience, these geographers recognize regulation as a process of temporal and spatial unevenness influenced by the interaction of forces within and through various places and institutions *(Clark et al. 1992, Peck and Tickell 1992, Painter and Goodwin 1995, Goodwin and Painter 1996, MacLeod 1997, MacLeod and Goodwin 1999).* Rather than treat the mode of regulation as fixed, these geographers emphasize the *process* of regulation at local and national scales.

> [T]he ebb and flow of regulatory processes through time and space. At certain times and places those processes will be more effective than at others. The process of regulation is the product of material and discursive practices that generate and in turn are conditioned by social and political institutions. This challenges the view of the history of regulation as marked by stable and coherent phases separated by brief, but sharp, discontinuities *(Painter and Goodwin 1995, 342).*

Regulation as a process agrees with the administrative-law perspective of regulation, or what some geographers call “real” regulation *(Clark 1992, Marden 1992)*. Administrative law lies within the domain of public policymakers and regulatory agencies, tasked with striking the correct economic, political, and social balances between government and markets while weighing the interests of multiple stakeholder groups *(see figure one, page 144)*. It is context-sensitive, with substance provided through the discursive practices of legal and political institutions.

> The slate on which the economist-regulator writes is scribbled with the scratchings of lawyers, jurists, and politicians; the world to which he would apply his principles is excruciatingly imperfect and resistant; and the compass he needs is one that would help him thread his way through the thickets of second best. The really challenging job is deciding not what the ultimate economically rational equilibrium should look like, but what is economically rational in an irrational world, and how best to get from here to there *(Kahn 1979, 1)*.

To understand regulation in context, it is important to understand the (1) form and function of regulation in a particular capitalist society, and (2) relationship of regulation with the regime of capital accumulation and processes of industrial change and restructuring *(Marden 1992, 751)*.

Popular evolutionary theories used to explain industrial change generally neglect the influence of regulation, and assume that changes arise from the intrinsic interaction of technological advances and market forces *(Chapman 1992, 59)*. For example, the life-cycle theory posits that the evolution of industries can be explained in terms of the product cycle, where the penetration of new geographic markets is a response to product maturity in established markets. Underlying the shifts to new geographic areas are changes in the technology of production combined with a search for profitable production locations *(Vernon 1966)*.

The life-cycle theory was derived primarily from empirical induction within a realist paradigm *(Storper 1985, 261)*, but is often applied in positivist research using formalized models *(Norton and Rees 1979, Markusen 1985)*. Some geographers criticize formalized life-cycle models as deterministic and general, choosing instead to think in terms of industry development paths that relate to a shifting balance between centripetal and centrifugal forces *(Storper 1985, Taylor 1986)*. Centripetal forces encourage industrial centralization while centrifugal forces encourage industrial decentralization. Centripetal forces include economies of scale and vertical or functional integration, while centrifugal forces include regional political-economic differences, natural or man-made spatial barriers, and the transportation effects of distance *(McNee 1961)*. The centripetal-centrifugal concept originated in political geography where, within the U.S. federalist system, federal regulation is a centripetal force and state regulation is a centrifugal force *(Hartshorne 1950)*.

The dynamic interaction of centripetal and centrifugal forces, influenced by intrinsic and extrinsic factors, conflicts with a formalized analysis that seeks mechanical relationships among variables within a closed system. A closed system would normally hold extrinsic factors constant, using a form of empirical reductionism to exclude them from the analysis *(Storper 1985, 277)*. Analyzing extrinsic factors requires an open system, which requires a greater degree of specificity than formalized life-cycle models allow *(Tiemstra 1992)*. Factors extrinsic to a life-cycle model, including government regulation, can significantly influence the development of an industry by changing the political-economic environment in which it operates *(Chapman 1992, 59)*. To understand these processes, the particularities of an industry must be considered and more complex forms of explanation employed.

> [T]he theoretical agenda of economic geography must have, at its head, the integration of location and regional studies with the historical study of economic and political development…. The formidable but exciting task facing economic geography, then, is to integrate the analysis of locational logic with the historical human geography of modern political economics by directing attention to the *dynamics* of geographical industrialization *(Storper 1985, 277).*

Geographers have examined local and national regulation with respect to U.S. union elections *(Clark 1989a)*, worker-safety laws and court cases *(Blomley 1990)*, plant-closing legislation *(Clark 1991)*, British food policy *(Harrison et al. 1997)*, welfare and workfare systems *(Peck 2002)*, the restructuring of New York City's water supply *(Gandy 1997)*, and the privatization of the British water system *(Bakker 2000)*. This study adds to an emerging body of literature, focusing on the local-national regulatory interface as it relates to industrial restructuring. Here, the federalist regulatory apparatus provides a political-economic framework within which to examine the restructuring of the U.S. electricity industry. Combining French regulation theory with "real" regulation allows for contextual analysis of the processes and particularities behind restructuring.

Chapter Two: Philosophy and Methodology

Unlike “the geography of enterprise” or “corporate geography,” this study subordinates the roles of agency and the individual firm *(Dicken and Thrift 1992),* and instead adopts an industry perspective *(Walker 1988, 1989; Storper and Walker 1989)*. “Rather than understanding industrial transformation through the restructuring of the operations of individual firms, the point of departure for analyses in economic geography should be some conceptualization of an industrial system” *(Dicken and Malmberg 2001, 358)*.

> [F]irms have to be understood as parts of broader industrial systems…. Focusing on systems means, in a way, downplaying the significance and role of firms, in the same way as sociological analyses of the dynamics of social groups and networks tend to downplay the physical and mental attributes of individuals. A systemic approach forces us to concentrate on structures at the macro or meso scale *(Dicken and Malmberg 2001, 349)*.

Walker *(1989, 50-51),* in his critique of corporate geography, asserts that spatial patterns of growth and change are better examined in terms of industries rather than individual firms, and industrial geography must be more “fruitfully” joined with spatial theories of capital accumulation. Five insights from Walker’s critique relate to this study of the U.S. electricity industry. First, industry is not composed of discrete, self-organizing, and self-defining commodity production systems. Instead, production systems are dynamic, interconnected, and complex. Second, the existence of the market, as an institution built of laws, people, and practices, is as much in need of explanation as the firm. Third, space and place affect modes of organization and production, and the industrial impacts of government policies must be recognized. Fourth, governments do not just make policies, but are embedded, dynamic participants in industrial organization and reorganization. Finally, the circulation of capital is the key arbiter of capitalist production, and capital movement directly affects modes of organization and production *(Walker 1989, 54)*.

The "industry versus firm" perspective parallels the "structure versus agency" debate often associated with "structuration" theory *(Giddens 1979)*. Structuration theory has been combined with time-geography, using concepts of "path" and "project," to explain "place" as historically contingent process: "The detailed situations and material continuity of structuration are perpetually spelled out by the intersection of individual paths with institutional projects occurring at specific temporal and spatial locations" *(Pred 1984, 282)*. The ways in which paths and projects intersect are not subject to universal laws but vary with historical circumstances. Within place-bound structuration processes, institutional projects contain the primary path-project intersections and are the product and source of the most significant structural properties. Power relations hold structuration processes within institutions, and these power relations can be transformed only by the modification of already-employed project definitions and rules, or by the total elimination of a project *(Pred 1984, 289-90).*

With its industry rather than firm perspective, this study is primarily a "structuralist" inquiry into the U.S. electricity industry as a whole *(Johnston 1980, Eyles and Lee 1981, Pred 1984, Morris 1988),* including the organization and reorganization of production and delivery systems, the shifting balance between government and markets, and the industry's interaction with the state and federal regulatory environments. The advantage of the structuralist approach is that it permits simultaneous conceptualization of industrial systems and territories at multiple scales. It thereby allows inter-scalar analyses of the regulatory interactions between those systems and territories.

> The institutions and processes of governance -- the sets of institutions, rules, and conventions that form the regulatory context of industrial systems, firms, and territories -- pervade all aspects of the firm-territory nexus. Such governance elements operate at a range of geographic scales.
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> ….
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> The governance systems that envelop and regulate firms and territories may be general to the economy as a whole or specific to particular segments of the system (e.g., individual industries) *(Dicken and Malmberg 2001, 346-47)*.

Although this study operates at the sub-national and national scales, geographers also have adopted an industry perspective at the global scale *(Dicken 1992, 1994, 2003)*. For example, Dicken *(2003, 317-506)* examines five global industries: the textiles and garments, automobile, semiconductor, financial services, and distribution industries. In each of these five industry studies, Dicken incorporates an analysis of the regulatory environment and role of the state. With respect to the textiles and garments industry, he examines the influence of the international Multi-Fibre Arrangement and other multilateral treaties *(Dicken 2003, 337-39)*. For the automobile industry, he examines country-specific policies impacting trade and foreign direct investment *(Dicken 2003, 369-72)*. With the semiconductor industry, he examines country-specific policies for promoting industrial development *(Dicken 2003, 410-19)*. For financial services, he notes that “[t]he accelerating deregulation of financial services is the most important current development in the internationalization of financial services” *(Dicken 2003, 449)*.

Finally, with distribution industries, he examines the regulation and deregulation of transportation and communications systems as they relate to the cross-border movement of goods and services *(Dicken 2003, 481-85)*.

While other studies have acknowledged the regulatory environment's influence on industrial change and restructuring, in this study it plays a central role. The U.S. electricity industry is an unusually effective vehicle through which to study the intersection of regulation and industrial restructuring. First, the industry has dedicated institutional and regulatory frameworks, while for other industries the relevant frameworks are less discernable. Second, substantial institutional data exist in the form of reports, administrative proceedings, congressional hearings, and court cases, which encapsulate the "discursive structuralisms" of the restructuring process. Finally, the evolutions of the industry's operating structure, production characteristics, and dual regulatory system match the temporal and substantive characteristics of Fordism and late capitalism *(Knudsen et al. 1994)*.

The U.S. electricity industry's dual regulatory system emerged with a series of Supreme Court cases culminating in *Rhode Island Public Utilities Commission v. Attleboro Steam and Electric Co.*, 273 U.S. 83 (1927). The *Attleboro* court attempted to draw a "bright line" between state and federal jurisdiction over the electricity industry, by limiting state authority over interstate electricity transmission and sales-for-resale. The court held that states were constitutionally prohibited from regulating interstate electricity commerce. Because the role of federal regulation at that time was unclear, *Attleboro* caused interstate electricity transactions to go unregulated.

The dual regulatory system for electricity solidified during the New Deal era of the 1930s, with federal legislation that *inter alia* attempted to close the jurisdictional gaps that had become known as "Attleboro gaps." The operating structure of the U.S. electricity industry also solidified in the 1930s, under central production within franchise service territories, emphasizing vertical integration and economies of scale. The dual regulatory system and operating structure remained largely unchanged until the 1970s when reduced scale economies, more decentralized and flexible production systems, and emerging vertical de-integration converged with the start of deregulation.

"Real" regulation within the U.S. federalist context began with the establishment of the Interstate Commerce Commission (ICC) in 1887. The ICC became the model for various New Deal institutions of the 1930s, including the Federal Power Commission (FPC). In part, these institutions were established under the belief that the market could not be adequately managed through the state-based court system. There was a spatial shift in control of the market to the federal level, a move toward regulating entire industries, and a belief in the ability of central institutions to address market failures *(Clark 1992, 616-17).*

The New Deal is thought by many to be the source of legal theory and regulatory instruments that provided the framework for the Fordist economy *(Aglietta 1987).* In the 1930s, U.S. legal theory was dominated by "legal realism," which had displaced the "legal formalism" of the earlier twentieth century. In general, Realists understood law as a human product contingent on time and place, while Formalists emphasized the logic of abstract legal concepts *(Frank 1930, 1949; Llewellyn 1930, 1962; Cohen 1935; Rumble 1968).* Under legal realism, "theory took as its object the way law worked in practice, breaking down the intellectual walls between law, politics, society, and culture" *(Scheppele 1994, 386)*. It was in this setting that federal regulation of the U.S. electricity industry began. By the 1960s, legal theory had begun to embrace "public-choice" theory *(Buchanan and Tullock 1962)* and ideas from the Chicago school of law and economics *(Posner 1992)*. It was in this setting that federal *de*regulation of the U.S. electricity industry began.

In the 1980s, "critical legal studies" arose from the academic left as a counterbalance to the law and economics movement *(Hutchinson 1989)*. Also beginning in the 1980s, the new "literary theory" challenged assumptions about the stability of social texts and legal doctrine *(Sunstein 1990)*, giving birth to the "interpretive turn" *(Geertz 1983, Blomley 1987, Eyles 1988, Clark 1989b)*. Finally, by the late 1980s many legal scholars had embraced pragmatism, which invoked similarities to the legal realism of a half-century earlier *(Fish 1982, Minow and Spellman 1989, Brint and Weaver 1991)*.

Historically, legal theory and social theory have been closely intertwined *(Scheppele 1994)*, and this study benefits from the relatedness. The social-sciences methodology used here is rooted primarily in realism *(Sayer 1982, 1985, 1992; Lawson and Staeheli 1990)* and secondarily in pragmatism *(Rorty 1979, 1982; Fish 1982; Roth 1987)*. This approach allows for contextual analysis and explanation of the dynamics associated with regulatory change and industrial restructuring *(Eyles and Lee 1982, Smith 1984, Storper 1985, Eyles 1988, Barnes 1989, Proctor 1998)*.

In calling for more relevance in economic geography, a number of geographers have advocated a realist approach *(Eyles and Lee 1982, Morris 1988, Bailly and Coffey 1994)*. Realism means embracing an open rather than closed system and emphasizing processes in time rather than end-states, fixed points, or equilibrium. Unlike positivism, realism contemplates a stratified reality in which causal powers emerge from the structural relationships between objects *(Sayer 1992, 118-121)*. With this approach, analysis and "thick description" *(Sayer 1992, 262)* are applied to the structures and mechanisms that produce or influence a phenomenon of interest.

> [S]ocial science has been singularly unsuccessful in discovering law-like regularities. One of the main achievements of recent realist philosophy has been to show that this is an inevitable consequence of an erroneous view of causation. Realism replaces the regularity model with one in which objects and social relations have causal powers which may or may not produce regularities, and which can be explained independently of them. In view of this, less weight is put on quantitative methods for discovering and assessing regularities and more on methods of establishing the qualitative nature of social objects and relations on which causal mechanisms depend *(Sayer 1992, 2-3).*

Three basic themes comprise the realist process of conceptualization. First, Realists often combine several bodies of theory to explain social complexity. These researchers recognize that social processes operate at multiple scales and a multi-theory analysis transcends these scales. Second, realism examines empirical regularities and outcomes, but also distinguishes between questions concerning observable phenomena and those concerning the causal relations and processes that created them. Finally, realism reveals the illusoriness of social "facts" and recognizes that knowledge must be evaluated in a given context, not in terms of objective truths *(Lawson and Staeheli 1990, 14).*

In realist research, the process of conceptualization begins with abstraction and involves identifying the necessary relations by which social objects are empowered or constrained. Studies that incorporate several levels of abstraction allow geographers to abstract from concrete events toward the more complex systems in which they are situated *(Lawson and Staeheli 1990, 16-18)*. In this study, French regulation theory operates at a high level of abstraction, federalism at an intermediate level, and "real" regulation at a low level. Realism gives way to pragmatism at the low, institutional level of abstraction. Pragmatists would see no order or structure to regulation in an institutional setting. Instead, as an interpretive social practice, "real" regulation would be seen as an *ad hoc* exercise with numerous contextual contingencies *(Marden 1992, 761).*

Pragmatism influences this research in the area of theory, where the study adopts an instrumentalist methodology. Like positivism, pragmatism is grounded in experience and a commitment to the practical purpose of knowing. But unlike positivism, pragmatism does not pretend to separate knowledge from human interest. Theories are judged according to their utility in reducing the analyst's uncertainty, not in the sense of representing an external, objective reality *(Smith 1984, 361-62).*

> Pragmatism eschews large conceptual schemes in favor of contextualized knowledge. It starts from the present "here and now," rather than from imagined neutral places and times. It goes somewhere that will make a difference, doing only what is necessary to solve practical problems at hand. It is antifoundationalist, believing that knowledge has only the organization we bring to it and that the search for first principles inevitably turns up nothing very useful. To the pragmatist, truth comprises those things we know that hang together with everything else we believe to be the case. Theory is not what is done on special occasions; theory is what each of us does all the time to make sense of things *(Scheppele 1994, 400).*

Within geography and the social sciences, Smith *(1984, 369)* offers four comments on the philosophy of pragmatism. First, pragmatism is a "middle ground" in the structure-agency debate, focusing on the practical level of what can be achieved through intelligent intervention in an imperfect world, not on what is believed by faith to exist. Second, pragmatism recognizes the fact of moral and ethical disagreement among analysts and policymakers. Third, pragmatism is devoted to bridging the gap between academia and practical reality, a task often given mere lip service in social theory. Finally, pragmatism is a task-oriented philosophy that emphasizes the formulation of concepts in use, not in the abstract where they may have little practical relevance.

The first task of this study is to examine the legacy, market, regulatory, and technological factors underpinning the first wave of U.S. electricity restructuring. Unpacking and analyzing these factors will better inform participants and policymakers as the industry moves forward in the restructuring process. The second task is to examine the intersection of industrial restructuring with the mode of regulation. For the U.S. electricity industry, this intersection occurs where the formal institutional and regulatory frameworks meet with the external economies of vertical de-integration and flexible capital accumulation *(Piore and Sabel 1984; Harvey 1988, 1990; Scott 1988; Phelps 1992)*. How policymaking incorporates these external economies within the mode of regulation will determine the nature and success of restructuring *(Tickell and Peck 1992, Painter and Goodwin 1995, Goodwin and Painter 1996, MacLeod 1997, MacLeod and Goodwin 1999).*

As stated in chapter one, the broad question to be addressed is the following: how do overlaid state and federal jurisdictions, combined with the unique technological and regulatory characteristics of the U.S. electricity industry, impact restructuring? This broad question can be divided into two sub-questions, each with several related questions. First, how did the interaction of centripetal and centrifugal political-economic forces shape the first wave of restructuring, and what lessons can be applied as the restructuring process moves forward? Second, for the U.S. electricity industry, how do technology and the formal regulatory framework meet with the external economies of vertical de-integration and flexible capital accumulation?

The first sub-question calls for a review and evaluation of recent U.S. electricity restructuring. Three related questions concern the influence of federalism *(Dikshit 1971, Clark 1989a, Blomley 1990, Stalon and Lock 1990, Fels and Lindh 2001)*: (1) under 1990s federal deregulation associated with wholesale electricity trade, has the dual regulatory system allowed "gaps" in regulatory oversight? These gaps would be reminiscent of the "Attleboro gaps" that existed prior to the promulgation of 1930s federal regulation. (2) How can regulatory transition losses explain the industry consolidation and divestiture of the 1990s? (3) What are the implications of the overlapping regulatory framework for state and regional market design? A final related question addresses imperfect markets and regulatory failures: what regulatory lessons emerge from the events of California, Enron, and the Blackout of 2003?

The second sub-question calls for the examination of external economies within the changing technological and regulatory environments *(Piore and Sabel 1984; Harvey 1988, 1990; Scott 1988; Phelps 1992; Tickell and Peck 1992; Painter and Goodwin 1995; Goodwin and Painter 1996)*. For the industry, I identify the emerging external economies of vertical de-integration and flexible capital accumulation. They are (a) the financialization of electricity, including the use of derivatives; (b) physical and financial electricity trade via central exchanges and Internet platforms; (c) network convergence between electricity and natural gas; (d) decentralized production located near places of consumption, including small-scale distributed generation (DG); and (e) distributed real-time pricing and demand response.

The first related question concerns electricity trade: how and within what regulatory framework can electricity trade, both physical and financial, improve market efficiency and stability? A second related question addresses the restructuring of electricity production: how have regulatory and technological changes influenced locations and patterns of electricity production? The final related question addresses DG and distributed real-time pricing: what are the potential roles of DG and distributed real-time pricing in a restructured marketplace, and how does the regulatory environment influence their deployment?

For the U.S. electricity industry, the dominant government institutions are the (1) Department of Energy (DOE), which operates the Energy Information Administration (EIA); and (2) Federal Energy Regulatory Commission (FERC). The EIA collects data and publishes reports on the market, regulatory, and technological characteristics of the U.S. electricity industry. Wholesale electricity trade data from the EIA are used to examine gaps in the dual regulatory system. The FERC oversees the interstate transmission grid and wholesale markets, and collects data from industry participants. The FERC Form One Annual Report and a study by Kahal and Brown *(1997)* provide production-cost data used within the wholesale-trade analysis.

Recently, Congress also has been institutionally active in the electricity industry, as it considered new legislation and held hearings into the California, Enron, and Blackout events. For this study, contextual data come from EIA reports, FERC administrative proceedings, and the congressional hearings listed below. These texts are used to examine the discursive structuralisms shaping electricity restructuring, and excerpts are incorporated herein where useful.

Textual-interpretive analysis is an example of pragmatic interpretivism *(Rorty 1979, 1982; Fish 1982; Roth 1987)* and has been used effectively in other geographic research *(Blomley 1987, 1990; Clark 1989a, 1989b, 1991; Clark et al. 1992)*. It has much in common with phenomenology and hermeneutics, which in turn share elements of the structuralist perspective *(Gregory 1978, Marden 1992)*. Although incorporating discursive excerpts in a study is somewhat unorthodox, it nonetheless is an effective method of communicating both context and thick description. It also is an effective method of validation, where principles of validation are internal to the discourse itself, and logical inference is justified in terms of the presented evidence *(Eyles and Lee 1982, 117; Smith 1984; Eyles 1988, 10-11)*.

Hearings from the House Committee on Energy and Commerce

- *Blackout 2003: How Did It Happen and Why?* September 3 and 4, 2003.
- *Comprehensive National Energy Policy*; March 5, 12, and 13, 2003.
- *The Effect of the Bankruptcy of Enron on the Functioning of Energy Markets*; February 13, 2002.
- *National Electricity Policy: Barriers to Competitive Generation*; July 27, 2001.

Hearings from the House Committee on Financial Services

- *The California Energy Crisis: Causes, Impacts, and Remedies*; June 20, 2001.

Hearings from the Senate Committee on Energy and Natural Resources

- *Oversight on Electricity*; March 27, 2003.
- *Financial Condition of the Electricity Market*; March 4, 2003.
- *Standard Electricity Market Design*; September 17, 2002.
- *Western Energy Market Manipulation*; May 15, 2002.
- *Potential Effects of PUHCA Repeal on Energy Markets*; February 6, 2002.
- *Impact of Enron Collapse on Energy Markets*; January 29, 2002.

Hearings from the Senate Committee on Governmental Affairs

- *Keeping the Lights on: the Federal Role in Managing the Nation's Electricity*; September 10, 2003.
- *Asleep at the Switch: FERC's Oversight of Enron Corporation*; November 12, 2002.
- *The Impact of Electric Industry Restructuring on System Reliability*; June 28, 2001.
- *The Role of the Federal Energy Regulatory Commission Associated with the Restructuring of Energy Industries*; June 20, 2001.
- *Economic Issues Associated with the Restructuring of Energy Industries*; June 13, 2001.

Chapter Three: Recent Events and Historical Overview

Recent Events

Shocks associated with California, Enron, and the Blackout of 2003 have dramatically changed the outlook for electricity restructuring *(Cudahy 2001, Duane 2002)*. The California crisis has primarily affected retail deregulation, while the Enron collapse and merchant-sector fallout have primarily affected wholesale deregulation. The Blackout has affected both retail and wholesale deregulation.

> [T]he expected outcome of regulatory reform … is not what it was even two or three years ago. The goal of markets that deliver the benefits of competitive prices, innovation and consumer choice without government intervention is worthy indeed. But recent history tells us that ideology must make room for realism and pragmatism. Electricity is like no other product consumed in the modern economy. It is necessary for economic well-being, safety and health; it cannot be stored; its demand varies continuously and often significantly over the course of an ordinary day; and it relies on massive and controversial physical infrastructure for delivery to consumers. *Remedying Undue Discrimination through Open Access Transmission Service and Standard Elec. Market Design*; NOPR, FERC Docket Number RM01-12-000; Issued July 31, 2002 (comment of the Am. Antitrust Inst., submitted Nov. 15, 2002).

California

In California, consumers and policymakers were jolted by price spikes, rolling blackouts, market manipulation, and a utility-company bankruptcy. In 1998, through Assembly Bill 1890, the California legislature opened retail markets to competition, giving consumers “direct access” to electricity suppliers. In attempting to establish competitive wholesale and retail markets, the California Public Utilities Commission

(PUC), with oversight and approval by the FERC, did the following: (1) they required the state's three investor-owned electric utilities (IOUs) to divest themselves of roughly half their power-plant capacity; (2) they froze retail rates through March 2002 or until IOU transition losses, commonly called "stranded costs," were fully recovered; and (3) they restricted the IOUs from entering into long-term supply contracts, forcing them to buy wholesale electricity through the newly formed California Power Exchange (PX) *(Michaels 2001, 338-39)*.

The IOUs were required to sell all output from their remaining power plants into the PX, which managed a wholesale "day-ahead" auction market. In the event of real-time supply and demand imbalances, the IOUs were expected to purchase electricity from the California Independent System Operator (ISO). The ISO was responsible for finding sufficient supply to meet demand in the spot market. As originally conceived, the ISO would supply electricity only to correct emergency system imbalances that could not be addressed through the PX day-ahead market *(Solomon and Heiman 2001, 463)*.

Beginning in the summer of 2000, insufficient electricity on the PX forced the IOUs to purchase from the ISO at elevated spot prices. Because the IOUs' residual regulatory mandate included an "obligation to serve," they continued to provide consumers with electricity even though the retail rate freeze would not allow recovery of wholesale costs. Eventually, Pacific Gas and Electric (PG&E) declared bankruptcy, with Southern California Edison (SCE) on the brink. For San Diego Gas and Electric (SDG&E), the rate freeze was lifted in July 1999 upon its full recovery of stranded costs, allowing it to raise retail prices and avoid insolvency. But SDG&E customers were outraged when rising wholesale prices resulted in a tripling of their electricity bills in the summer of 2000, and the California legislature imposed a rate cap in September 2000 *(Solomon and Heiman 2001, 464)*.

At various times, the ISO was unable to procure sufficient electricity, resulting in brownouts and blackouts. Eventually, the FERC intervened in response to consumer complaints of wholesale market manipulation. In a December 15, 2000 order, the FERC *inter alia* did the following: (a) eliminated the mandatory PX buy-sell requirement for IOUs; (b) created a benchmark price based on historical data, used to measure the reasonableness and prudence of bilateral contract prices; (c) required that market participants schedule ninety-five percent of demand or “load” prior to the real-time ISO market, limiting real-time balancing purchases to only five percent of the market’s total needs; and (d) initiated market-monitoring and price-mitigation plans *(Yuffee 2001, 75-77)*.

On February 1, 2001 the California legislature also intervened. Assembly Bill 1X authorized the California Department of Water Resources (DWR) to purchase electricity from wholesale suppliers, under long-term contract, on behalf of financially distressed PG&E and SCE. Concurrently, California officials increased pressure on the FERC to address wholesale prices that were not “just and reasonable.” Long-term electricity purchases by the DWR, combined with western price caps by the FERC in June 2001, eventually lowered California wholesale prices during the summer of 2001. However the state is now burdened with expensive long-term electricity contracts, retail prices are high, and PG&E and SCE remain financially troubled. California eliminated retail direct access in September 2001, effectively ending deregulation in that state *(Fellmeth 2002, 836-59)*.

California’s failed experiment has caused many states to rethink retail deregulation *(Solomon and Heiman 2001, 463)*. Prior to the California crisis beginning in the summer of 2000, twenty-four states had enacted enabling legislation or issued regulatory orders to implement retail competition. By the end of 2001, deregulation had been delayed or suspended in eight of those states *(see figure two, page 145)*. Eighteen other states with ongoing year-2000 investigations into deregulation at either the legislative or regulatory levels reported no activity in 2001 *(EIA March 2003, 1)*.

Enron

Furthermore, the Enron collapse and subsequent slump in the merchant energy sector have industry participants and regulatory agencies rethinking the benefits of wholesale deregulation and electricity trade. Enron was the largest electricity marketer and trader in the U.S., with year-2000 revenues of $101 billion, booked primarily through its Internet-based trading platform, Enron Online. Enron was the first mover in wholesale electricity trading, the most active proponent of deregulation, and the “market-maker” for most of the regional and national goods comprising the merchant energy sector. By the close of 2001, Enron was bankrupt and its electricity-trading and market-making business models discredited.

A number of other companies followed Enron into energy trading, and now face their own financial crises as the sector has contracted *(Herron 2003, Neves 2003)*. Plus, merchant electricity producers, responding to inflated prices in the wholesale markets, hatched ambitious expansion plans in 1999, 2000, and early 2001. As wholesale electricity prices fell following Enron’s collapse, plans to build new merchant power plants have been cancelled or dramatically reduced. Merchant producers that incurred debt to finance expansion now face cash shortages, credit downgrades, loan defaults, low stock prices, and potential bankruptcy.

The Blackout of 2003

Finally, the blackout of August 14, 2003 emerged as strike three to the existing mode of deregulation. In the traditional regulated environment, vertically integrated utilities had little incentive to sell electricity outside their franchise service territories, and most electricity traveled short distances. Over the past decade of deregulation, far-flung merchant production and wholesale electricity trade have encouraged the long-distance transmission of electricity, requiring broader and more sophisticated regional coordination to ensure reliability. An instantaneous balance between supply and demand must be delicately maintained along the transmission grid, and long-distance electricity sales contribute to overloaded transmission lines and unpredictable electron surges. These surges, when combined with inadequate regional coordination in response to local failures, can lead to cascading failures over large areas. With the Blackout of 2003, a cascading failure that began in Ohio darkened parts of eight northeastern states and eastern Canada, affecting roughly fifty million people *(Revkin 2003, Smith 2003a).*

> This outage took about 34,000 miles of our nation's 150,000 miles of high-voltage transmission lines out of service. More than 290 power generation units were tripped off line or shut down. Thousands of substations, switching facilities, circuit-protection devices, and other pieces of specialized equipment were affected, and a very large number of people, policies and procedures were involved. *Keeping the Lights On -- The Fed. Role in Managing the Nation's Elec.: Hearing Before the Senate Comm. on Governmental Affairs,* (Sept. 10, 2003) (statement of Kyle E. McSlarrow, Deputy Secretary of Energy).

Industry Overview

Historically, vertically integrated electric utilities were believed to have natural-monopoly properties. They are still believed to have such properties with transmission and distribution services, but no longer in electricity production. A natural monopoly arises when economies of scale are so pervasive that a single firm can offer the product or service cheaper than two, and fixed costs are so large that duplicating services is uneconomic. From early in the industry's history, U.S. IOUs were regulated at the local level to protect consumers against abuses of natural-monopoly power.

When a market is believed to be a natural monopoly, cost-of-service ratemaking is often imposed as a substitute for competitive market discipline. With IOU cost-of-service ratemaking, the state PUC seeks to determine the IOU's costs -- including the cost of raising capital -- in order to calculate the revenue required to cover those costs. From this revenue requirement the PUC derives retail prices to be charged, which include opportunity for return on investment. Because it is difficult to determine forward costs, revenue requirement and prices are often set on an historical basis *(Pierce and Gellhorn 1994, 88-89)*.

The revenue requirement uses the basic formula $R=O+B(r)$, where R is the revenue requirement, O is operating expenses, B is the rate base, and r is the allowed rate of return on the rate base. Once the aggregate revenue requirement is determined, the PUC calculates the amount that the IOU can charge customers. The regulatory constraint on total revenue is intended to (a) avoid prices above and output below competitive levels, (b) avoid a transfer of wealth from consumers to producers, and (c) yield a mix of price, output, and profits approximating that found in a competitive situation *(Pierce and Gellhorn 1994, 89)*.

In setting allowed rate of return, the PUC must consider four primary concerns: (1) fairness to investors, (2) fairness to consumers, (3) the IOU's need to attract capital, and (4) administrative simplicity *(Pierce and Gellhorn 1994, 128)*. The rate base, on which the IOU earns the allowed rate of return, represents investment in the capital assets used to provide the regulated services. In theory, the allowed rate of return is set equal to the IOU's cost of capital. An allowed rate of return below the IOU's actual cost of capital impedes access to the capital markets. An allowed rate of return above the IOU's actual cost of capital hurts consumers by providing a windfall to IOU stockholders, and by encouraging over-investment in capital assets to maximize actual return on investment *(Averch and Johnson 1962)*. Indeed, cost-of-service ratemaking is an imperfect process:

> Two conclusions should be drawn. First, efforts to obtain economic precision in the regulatory process … are unlikely to be worth the effort expended. The standard to which such efforts implicitly appeal is that of overcoming "distortions" produced by competitive market failure -- the standard of trying to replicate what would occur without such a failure. Yet in trying to overcome such failures the regulatory process introduces so many distortions of its own, that one should be satisfied with gross estimates and not insist upon refined economic calculation. Second, insofar as cost-of-service ratemaking is advocated as a "cure" for market failure, one must believe that the unregulated market is functioning quite badly to warrant the introduction of classical regulation. That is to say, the regulatory process -- even when it functions perfectly -- cannot reproduce the price signals that a workably competitive marketplace would provide. Thus, only serious market failure will, even arguably, warrant the adoption of cost-of-service ratemaking as a cure *(Breyer 1982, 59)*.

In the early decades of the twentieth century, as scale economies for electricity production and delivery increased, decentralized production became more central and IOU service territories expanded and merged, often across state borders. Consolidation of operating companies into multi-state holding companies (MHCs) led to interstate commerce. Stand-alone IOUs were primarily local in nature, regulated by state PUCs and municipal governments. In contrast, MHCs comprising multiple IOUs in multiple states invoked federal jurisdiction under the Commerce Clause of the U.S. Constitution. Because the Constitution reserves to the states those powers not expressly granted to the federal government, there exists a dual regulatory system. With the dual exercise of state and federal power, each dominant within its own sphere, regulation of MHCs became difficult. State PUCs were unable to maintain jurisdictional control, and generally lacked the resources to effectively regulate MHCs. Meanwhile, the correct role for federal regulation was unclear.

By 1932, eight “super holding companies” (SHCs) accounted for sixty-seven percent of privately generated electricity, and the three largest SHCs -- the Electric Bond and Share Company, J.P. Morgan’s United Corporation, and the Insull Group -- controlled almost half of U.S. IOUs *(Watkiss and Smith 1993, 450)*. Problems with the SHC structure included (a) regulatory difficulty; (b) abuses associated with the “pyramiding” of operating companies and holding companies, which resulted in excessive leverage and made SHCs more vulnerable to the business cycle; (c) questionable inter-company transactions and excessive service fees charged to subsidiary operating companies; (d) capitalization of excessive service fees into the accounts of the SHCs, which inflated the book values of operating companies and caused customer rates to increase; (e) overvalued SHC securities; and (f) competition among SHCs to continue acquiring operating companies and holding companies, encouraging them to purchase these entities at well above market value. Consumers paid for these abuses in higher rates and lower quality of service. Plus, investors would inevitably pay a price when the valuation "bubble" for SHC securities burst *(EIA January 1993, 1-5)*.

An investigation by the Federal Trade Commission (FTC) found five aspects of the holding-company structure that called for federal regulation: (1) states had made little progress in effectively regulating MHCs, (2) holding companies performed no producing function and therefore contributed nothing to the supply of electricity or economic wellbeing of the nation, (3) public investors had no voting rights or the rights were so widely dispersed that management could not be effectively opposed, (4) only federal legislation could close the regulatory gaps through which MHCs were organized, and (5) if the consolidation trend continued, all IOUs could eventually be concentrated within a single monopoly holding structure *(EIA January 1993, 5)*.

In 1935, the federal Public Utility Holding Company Act (PUHCA) was promulgated. Under PUHCA, the Securities and Exchange Commission (SEC) forced MHCs to divest until each became an integrated group of operating companies that were (a) physically interconnected, and (b) operated as a single consolidated utility system. PUHCA exempted those holding companies that operated predominately within a single state. The result was to confine most holding-company operations to only one state, where they could be more effectively regulated by a state PUC. Holding companies that maintained a multi-state operating structure were subject to both state and federal regulation. Virtually all of the existing holding companies were forced into radical reorganization *(EIA January 1993, 9-11)*.

The Federal Power Act (FPA) of 1935, companion legislation to PUHCA, created the FPC to oversee interstate operating activities. Under the FPA, federal regulators have authority to regulate the rates, terms, and conditions of interstate electricity transmission and wholesale sales by non-government entities. The states retain primary jurisdiction over electricity production and local distribution. The FPA was intended to fill gaps between state and federal regulation, illuminated by the U.S. Supreme Court in a series of cases culminating in *Rhode Island Public Utilities Commission v. Attleboro Steam and Electric Co.*, 273 U.S. 83 (1927). *Attleboro* and other cases defining the present-day dual regulatory system are listed below.

Court Case	Year	Decision
Munn v. IL (94 U.S. 113)	1877	Supreme Court establishes the rights of government to regulate and set rates for companies that provide vital public services in a business environment.
Smyth v. Ames (169 U.S. 466)	1898	Supreme Court decrees just compensation on fair value. The decision in this case upheld the right of a state to regulate the prices charged to the public by a business “affected with a public interest.”
RI PUC v. Attleboro (273 U.S. 83)	1927	Supreme Court declares that interstate electricity sales cannot be regulated by a state.
Otter Tail Power v. U.S. (410 U.S. 366)	1973	Supreme Court upholds finding that Otter Tail Power Co., an IOU, violated Section Two of the Sherman Act by refusing to sell or “wheel” wholesale electricity to proposed municipal systems.
Nantahala Power & Light v. Thornburg (476 U.S. 953)	1986	Among other outcomes, the Supreme Court confirms that the FERC has exclusive authority over wholesale electric rates.
MS Power & Light v. MS (487 U.S. 354)	1988	Supreme Court holds that FERC authority is controlling and that a state PUC is obligated to honor a FERC order. The Court states “FERC-mandated allocations of power are binding on states, and states must treat those allocations as fair and reasonable when determining retail rates.”

Northern States Power v. FERC (176 F.3d 1090)	1999	Eighth Circuit holds that the FERC lacks jurisdictional authority to require a transmission-owning utility to curtail firm transmission underlying its retail service on an equal basis with firm transmission performed for shippers of electricity in the interstate wholesale market.
NY v. FERC (535 U.S. 1)	2002	Supreme Court holds that the FERC did not exceed its jurisdictional authority by including unbundled retail transmissions within the scope of Order 888's open access requirements.

The dual regulatory system established in the 1930s remains in effect, with the industry still regulated at the state level by PUCs and at the federal level by the SEC and successor to the FPC, the FERC.

> The federal regulatory scheme for electric utilities is set forth in [PUHCA] and the [FPA]. Both laws were passed in the mid 1930s in response to corporate abuse by utility holding companies. Holding companies were taking advantage of the fact that they owned utilities in multiple states to engage in interstate, intra-company transactions that could not be controlled by state [PUCs]. The [SEC] was given authority to regulate matters relating to utilities' corporate structures under PUHCA, including the ability to restrict ownership of multiple utility companies by a single holding company. Under the FPA, FERC's predecessor agency -- the [FPC] -- was given the authority to regulate the rates that could be charged for electricity sold by one utility to another. The FPA required that these wholesale electric rates be "just and reasonable" and nondiscriminatory…. This statutory standard remains in place today. State [PUCs] continue to regulate retail rates charged to consumers within their states. The electricity industry in the U.S. has historically been characterized by vertically integrated utility companies that owned and controlled generation, transmission and distribution systems necessary to serve their own customers. These systems were primarily regulated by state [PUCs] which approved construction of the facilities necessary to provide electric service and consumer rates to recover the cost of those facilities. Generally, sales of power between utilities were overseen by FERC. *Asleep at the Switch -- FERC's Oversight of Enron Corp.: Hearing Before the Senate Comm. on Governmental Affairs,* (Nov. 12, 2002) (statement of Majority Staff).

Until the 1970s, steady technological improvements and rising economies of scale kept the costs and prices of electricity service relatively constant, and declining in real terms. For example, from 1960 through 1970 the price of electricity declined by thirty percent in real terms. The decline is attributable primarily to innovations that increased the thermal efficiencies of steam-turbine generators. The amount of heat input to a steam turbine, measured in British thermal units (Btus), needed to produce a kilowatt-hour (kWh) of electricity decreased by almost forty percent between 1925 and 1945, and by thirty-five percent between 1945 and 1965. By the 1970s, improvements in steam-turbine efficiencies had stalled and could no longer offset rising costs in other areas *(EIA March 1993, 36-40)*.

In the 1970s, cost and price structures were impacted by fuel-price shocks, high interest rates, increased operations and maintenance (O&M) costs, nuclear-related costs, and environmental initiatives. Larger power plants no longer produced electricity at lower costs, and increasing returns to scale ceased to be a source of cost and price declines. From 1973 to 1982, electricity prices rose much faster than overall inflation. The nominal price of electricity approximately tripled while the implicit price deflator for the gross domestic product (GDP) only doubled *(EIA March 1993, 36-41).*

In the early days of the U.S. electricity industry, increasing returns to scale for central production contributed to the dominance of utility generators and the decline of non-utility generators (NUGs). More than a half-century later, NUGs returned under the federal Public Utility Regulatory Policies Act (PURPA) of 1978. PURPA forced incumbent utilities to accommodate the entry of NUGs into their franchise territories. It created a type of NUG called the Qualifying Facility (QF), with the underlying goals of reducing the nation's dependence on foreign energy and promoting efficient and environmentally friendly electricity production. QFs are power plants that use efficient cogeneration technologies or plants of less than fifty megawatts (MW) that use renewable technologies *(EIA December 1996b, 27-28)*.

To promote the use and development of cogeneration and renewables, PURPA mandated that an IOU purchase electricity from a local QF under long-term contract at the IOU's avoided cost of production, as determined by the state PUC. Avoided cost was defined as the cost that an IOU would not incur in meeting the requirements for universal and reliable service, because the QF was producing the electricity instead of the IOU. PUC-established avoided-cost figures proved largely inaccurate, especially as fuel prices declined in the 1980s, and IOUs began resisting QF purchase costs they perceived as excessive. By the late 1980s, many PUCs had moved to a competitive-bidding method to set the price at which an incumbent IOU would buy electricity from a new QF. QFs either supplanted existing capacity or discouraged IOUs from building new production capacity themselves *(EIA December 1996b, 27-28)*. In the years following PURPA, non-utility production companies, commonly called independent power producers (IPPs), emerged.

Also in the 1970s, at the same time that PURPA was promulgated, many IOUs were expanding production capacity, expecting growth in electricity demand that never materialized *(Joskow and MacAvoy 1975)*. In particular, IOUs began building approximately one-hundred nuclear power plants that were later cancelled. With a ten- to twelve-year lead time for construction of a major power plant, the decision to build these plants was made in the mid-1970s when IOUs were forecasting continued seven-percent yearly demand growth. At that growth rate, the IOUs would have needed twice the production capacity at the end of the ten to twelve years. IOUs were also forecasting that oil and gas prices would continue to escalate rapidly, making nuclear plants a prudent alternative. But actual demand for electricity increased by less than three percent annually, and oil and gas prices declined after several years of sharp increases. Nuclear power became much more expensive than the alternatives. The sharp disparity between forecast and actual conditions meant that, in retrospect, these one hundred or so nuclear plants were imprudent and most were cancelled in mid-construction *(Pierce and Gellhorn 1994, 116-18).*

State PUCs were then tasked with deciding whether and to what extent an IOU could recover its investment in a partially completed capital asset. Or, if the power plant was completed, the PUC had to decide how to deal with the excess capacity. In the 1980s this became a significant issue, with partially completed nuclear plants representing total capital investment losses of tens of billions of dollars. In each case, the IOU filed a request for rate increase to recover its lost investment plus a return on that investment. IOUs also tried to recover costs, with a return on investment, associated with completed power plants that represented expensive excess capacity *(Pierce and Gellhorn 1994, 118-19).*

Typically, a PUC responds in one of four ways to cost-recovery requests for a cancelled plant, or a completed plant that constitutes excess capacity: (1) disallowance of the cost as imprudent; (2) disallowance on the basis that the plant is not “used and useful;” (3) allowance for full recovery of the investment in the plant over several years, including a return on investment; and (4) in the case of a cancelled plant, allowance for recovery of the investment in the plant over several years, but disallowance of a return on investment. The first two place all costs on the IOU, the third puts all costs on consumers, and the fourth divides the costs between the IOU and consumers *(Pierce and Gellhorn 1994, 119-20).*

Through “prudence reviews” in the 1980s, PUCs regularly disallowed cost recovery for cancelled plants and excess capacity, leaving IOUs with inadequate revenue and significant debt burdens. IOUs viewed these disallowances as unprecedented, representing unfair retroactive changes in the rules of the game and a violation of the “regulatory compact.” The massive disallowances of the 1980s created an environment in which most IOUs were reluctant to invest in new power plants, considering the regulatory risks too high. Many in the industry believed that IOUs would be better served if they instead purchased electricity from IPPs. This change in attitude contributed significantly to the adoption of competitive contracting for wholesale electricity supplies *(Pierce and Gellhorn 1994, 122-24)*.

PUHCA prohibitions on business diversification made it difficult for IOUs to manage financial burdens associated with overpriced QF contracts and regulatory disallowances. PUHCA restricted the types of acquisitions that could be made, because any acquired entity had to form part of an integrated utility system. Similarly, IOUs were restricted from participating in the new market for independent power. A few IOUs participated in the independent power market by establishing subsidiaries that held minority interests in QFs, but on a very limited basis. Constraints also prevented IPPs from purchasing IOUs, because that would place the IPP under the jurisdiction of

PUHCA and require that the IPP divest all holdings that did not fit within an integrated utility system *(EIA January 1993, 25)*.

Beginning in the 1980s, some industry participants began calling for repeal of PUHCA. In fact, as early as the mid-1980s the SEC determined that PUHCA had achieved its purpose and recommended repeal, indicating that its regulations were antiquated and would impede the transition to competition. Others believed that PUHCA should remain intact, for the protection of consumers, until the industry completed the transition to competition. The debate continues into the present. Arguments for and against PUHCA repeal are summarized below *(EIA December 1996b, 39-41)*.

Against repeal	**For repeal**
PUHCA regulations can protect consumers until full retail competition is in place.	PUHCA's provisions are antiquated.
Ratepayers are still dependant on regulated monopolies.	PUHCA hampers the transition to competition.
PUHCA protects against anticompetitive behavior.	IOUs must be able to diversify in order to improve profits.
IOUs are now taking actions (e.g., mergers) to increase market power, and PUHCA can keep them under control.	By making holding companies manageable and regulated, PUHCA's goals have been met.
Immediate repeal is inadequate and piecemeal; repeal should be part of comprehensive restructuring legislation.	The SEC itself recommends a conditional repeal.
PUHCA guards against inter-affiliate transaction abuse.	PUHCA prevents a level playing field.
Lessons learned from California and Enron make PUHCA and its enforcement more important than ever.	Other legislation and regulations have since been enacted that prevent holding-company abuse.
	It will take too long to complete comprehensive restructuring legislation, and immediate repeal is necessary.

EPAct of 1992 modified the federal regulatory environment for IOUs in several ways. First, it relaxed PUHCA restrictions on domestic merger and acquisition activity, diversification into non-utility businesses, and investment in foreign utilities. Second, it authorized the FERC to order access to transmission networks, with incumbent utilities providing wholesale "wheeling" services over their transmission lines at cost-based rates. Finally, it created a new category of NUG called the exempt wholesale generator (EWG), which paved the way for IPPs to assume the risks of building and operating power plants *(Watkiss and Smith 1993).*

Although EWGs participate in interstate electricity markets, these merchant power plants are exempt from PUHCA's geographic operating restrictions. Plus, unlike QFs, they are not required to commit all output to utilities at fixed prices under long-term contract, but instead may sell into the spot and forward markets. Despite the diversification restrictions still imposed on IOUs by PUHCA, EPAct now allows non-utility subsidiaries of IOUs to build EWGs, or purchase power plants and reclassify them as EWGs *(EIA January 2003).*

In 1992, public and private utilities accounted for ninety-one percent of U.S. electricity production, while NUGs accounted for nine percent *(EIA October 2000, xi).* By 2001, utilities accounted for seventy percent of U.S. production while the NUG contribution had increased to thirty percent *(EIA February 2003a, 95).* The trend toward NUG production as a larger percentage of total production was furthered by some IOUs that focused, either by choice or state mandate, solely on their regulated transmission and distribution (T&D) services. These IOUs either reclassified their power plants as EWGs and transferred them to non-utility subsidiaries, or sold them to IPPs or non-utility subsidiaries of other IOUs *(EIA January 2003)*.

PUHCA still discourages an IOU from merging with or acquiring another IOU not connected to it by high-voltage transmission lines. Without this interconnection, the combined entity would not be able to operate as a single integrated utility system, as required. At the federal regulatory level, adjacent domestic service territories -- which can be integrated as a single utility system -- are readily joined through merger or acquisition, but utility diversification by IOUs into distant regions of the U.S. faces more regulatory scrutiny. Additionally, a state PUC can impede mergers and acquisitions permitted by PUHCA and federal agencies if it believes that the combined entity will have harmful intrastate market power *(EIA December 1999)*.

Mergers are not new to the U.S. electricity industry. From 1917 through 1930, electric-utility consolidations occurred at a rate of more than two hundred per year, peaking at over three hundred per year in the mid-1920s. Most of these mergers combined small operating companies into large holding companies, eventually prompting the PUHCA reform of 1935. Between 1935 and 1950 more than 750 utilities were spun off from the holding companies. Following the breakup of large holding companies, consolidations still occurred but at a much lower rate. In contrast to earlier mergers, the mergers of the past decade have been “mega-merger” combinations of large utilities *(EIA December 1996b, 88-92)*.

Liberalization of the transmission sector has advanced separately from liberalization of the production sector. In the first few years following EPAct, the FERC reviewed applications and rate proposals for wholesale wheeling services on an individual basis. That changed with FERC Order 888 of 1996, which asked incumbent IOUs to post pro-forma tariffs, approved by the FERC, for “open-access nondiscriminatory transmission services” available to wholesale electricity suppliers. Wholesale marketing and trading operations, either independent or affiliated with merchant production companies, formed to broker transactions between buyers and sellers and pursue arbitrage opportunities *(EIA October 2000)*. Regional electricity trading pools, central power exchanges, and wholesale spot and forward markets developed *(see figure three, page 146)*.

Also around 1996, state PUCs -- primarily from states with high retail electricity prices -- began experimenting with retail competition. Under retail deregulation, incumbent IOUs must allow formerly captive consumers to choose an alternative electricity supplier. As various states deregulated their retail sectors, some marketers moved downstream into the distribution channel, selling electricity directly to consumers under retail “direct-access” programs. These competitive suppliers buy electricity in the wholesale markets, with retail distribution over the lines of incumbent utilities.

Following FERC Order 888, the question remained as to whether incumbent IOUs should be allowed to maintain ultimate control over physical access to electricity markets. To ensure fair competition and equal access to markets, many policymakers believed that IOUs should relinquish control of their transmission systems to ISOs or regional transmission organizations (RTOs) *(see figure four, page 147)*. In December 1999, the FERC issued Order 2000, which asked all transmission-owning utilities to “voluntarily” place their transmission facilities under the control of RTOs, with details to be worked out by participants. By the fall of 2001, with slow progress toward the goals of Order 2000, the FERC began actively engaging state PUCs and industry participants to hasten the development of a standard RTO design *(American Bar Association 2002, 159).*

On July 31, 2002, the FERC issued a notice of proposed rulemaking (NOPR) for public comment. This NOPR, called the Standard Market Design (SMD), further defines the expectations for RTOs and proposes uniform market rules. The proposed rules are modeled after procedures used by the Texas ISO, which is physically separate from the rest of the U.S. electrical grid. In the analysis leading up to the NOPR, the FERC found that if transmission-owning utilities joined RTOs, market power would be mitigated and residual discriminatory access could be eliminated. They further determined that standardized market rules, tariffs, and business practices would ensure seamless operation of the U.S. market regardless of the number of RTOs *(American Bar Association 2002, 160)*. In the past, the FERC has supported the development of four RTOs, with the Texas ISO as a fifth.

While the FERC was developing the SMD, it also was examining the issue of independent producer interconnection to the transmission grid. In July 2003, the FERC issued a Final Rule on "Standardization of Generator Interconnection Agreements and Procedures." Inconsistency and uncertainty of interconnection rules among states and utilities were believed to discourage or slow investment in new power plants. This rule, which applies to large generating units of twenty MW or more, seeks to replace the state patchwork of interconnection procedures with a single set of national procedures.

Also in July 2003, the FERC issued an NOPR on "Standardization of Small Generator Interconnection Agreements and Procedures." This initiative applies to DG and other small generating units of less than twenty MW. DG is modular production sited near the place of consumption using technologies including diesel engines, fuel cells, microturbines, and photovoltaics. Despite the local nature of DG, the FERC advocates federal jurisdiction over DG interconnection to the distribution system, believing it is better able than state PUCs to manage incumbent-utility opposition *(Allen 2002)*. Spatially, DG brings the industry full circle. Over a century ago, the very first generators were decentralized and marketed to commercial and industrial users, just as the new DG technologies are today.

The table below summarizes the major legislative and regulatory actions relevant to the restructuring of the U.S. electricity industry.

	Year	**Effect**
Public Utility Holding Company Act (PUHCA)	1935	Placed geographic and business restrictions on investor-owned electric utilities (IOUs) to remedy abuses facilitated by the holding-company structure. Limited most IOUs to contiguous and primarily intrastate operating areas, and restricted diversification into unregulated non-utility businesses.
Public Utility Regulatory Policies Act (PURPA)	1978	Introduced conservation and efficiency programs in response to the fuel shocks of the 1970s. Created a class of non-utility generator (NUG) called the qualifying facility (QF) from which utilities are required to buy power at avoided cost.
Energy Policy Act (EPAct)	1992	Loosened PUHCA's geographic and business restrictions and created a class of NUG called the exempt wholesale generator (EWG). Authorized the FERC to open the national transmission system to competitive wholesale electricity suppliers.

Federal Energy Regulatory Commission (FERC) Order 888	1996	Gave wholesale electricity suppliers access to utility transmission lines under "non-discriminatory open-access tariffs" reviewed by the FERC.
FERC Order 2000	1999	Encouraged utilities to "voluntarily" surrender control of their transmission lines to independent regional transmission organizations (RTOs).
FERC Notice of Proposed Rulemaking (NOPR) for a Standard Market Design (SMD)	July 2002	Seeks to impose uniform market rules on regional electricity markets and hasten the formation of RTOs.
FERC Wholesale Power Market Platform White Paper	April 2003	FERC's restatement of the SMD proposal, reflecting intervening comments from stakeholders.
FERC Final Rule for Standardization of Generator Interconnection Agreements and Procedures	July 2003	Requires transmission utilities to adopt a standard interconnection agreement and set of procedures and provide interconnection services for electric generators of twenty megawatts (MWs) or more.
FERC NOPR for Standardization of Small Generator Interconnection Agreements and Procedures	July 2003	Seeks to create a standard interconnection agreement and set of procedures for the interconnection of electric generators of less than twenty MW.

Sources: EIA and FERC

Before continuing, several technical characteristics of electricity production and delivery should be addressed. First, electricity is a non-storable good. In other words, production must balance consumption at all times throughout the network, and power plants constantly change output to maintain equilibrium. Second, as with most perishable goods, the farther electricity is transported the more is lost, and the higher and more uncertain are the transportation costs. This encourages production near places of consumption, with scale economies as a mitigating factor. Third, because electricity follows the path of least resistance under the laws of physics, the problems of “loop flow” and “parallel-path flow” along the transmission grid make precise delivery difficult. Finally, delivery of electricity is subject to transmission limitations, including bottlenecks that result in “congestion.” In fact, because of the physics of electricity and limited transmission capability, U.S. wholesale electricity markets are primarily regional.

Chapter Four: Federalism, Imperfect Markets, and Regulatory Failures

This chapter addresses the first sub-question introduced in chapter two: how did the interaction of centripetal and centrifugal political-economic forces shape the first wave of restructuring, and what lessons can be applied as the restructuring process moves forward? Three related questions address issues of federalism: (1) under 1990s federal deregulation associated with wholesale electricity trade, has the dual regulatory system allowed "gaps" in regulatory oversight? (2) How can regulatory transition losses explain the industry consolidation and divestiture of the 1990s? (3) What are the implications of the overlapping regulatory framework for state and regional market design? A final related question addresses imperfect markets and state-federal regulatory failures: what regulatory lessons emerge from the events of California, Enron, and the Blackout of 2003? Each of these four questions is addressed in turn below.

First, under 1990s federal deregulation associated with wholesale electricity trade, has the dual regulatory system allowed "gaps" in regulatory oversight? These gaps would be reminiscent of the "Attleboro gaps" that existed before the 1930s federal regulation of interstate electricity sales. Borrowing principles from international economics, I examine trade characteristics for IOUs and seek evidence of Attleboro-type regulatory gaps within the stratified and balkanized state and federal jurisdictions.

To maximize collective profits, a multinational firm may engage in intra-firm trade and transfer pricing to avoid country-specific tariffs, taxes, or price caps *(Lall 1973, 178)*. Government price caps are typically based on production costs, analogous to retail electricity rates set by state PUCs. Intra-firm trade can have "trade-diverting" effects, meaning that more economically efficient and consumer-beneficial "open" trade is subordinated to the profit-maximizing interests of the firm *(Lall 1973, 189)*. Because transmission lines have limited capacity, trade among IOU affiliates of MHCs may create barriers to market entry by excluding other wholesale electricity suppliers from the delivery channels. First, I seek evidence that MHCs engage in discriminatory intra-firm trade. Then I seek evidence of profit-maximizing behavior that skirts the jurisdictional boundaries between state and federal regulation.

Wholesale trade characteristics for "stand-alone" IOUs are compared with trade characteristics for "holding-company" IOUs affiliated with MHCs. A stand-alone IOU is regulated primarily by a single state, while an MHC is regulated by multiple states and the federal government. The multi-state structure of MHCs may allow them to engage in activities that exploit gaps between state and federal oversight, thereby subverting the objectives behind 1990s wholesale deregulation *(Stalon and Lock 1990, Penniman and Turner 1999, Fels and Lindh 2001)*.

FERC Order 888, released in 1996, called for "non-discriminatory open access" to IOU transmission systems, after which some systems have become gradually and partially more accessible to non-incumbents. Other FERC initiatives followed, with mixed success, and the push for non-discriminatory access continues into the present.

> In 1996 … Order 888 … spurred competition in wholesale power markets by requiring [IOUs] to open their transmission systems to competing power providers on a non-discriminatory basis. The FERC followed that action, in December 1999, by issuing Order 2000, which established rules to encourage transmission-owning utilities to relinquish operational control … while still maintaining ownership of their power-grid assets and receiving revenues from their use…. [I]t has become evident that FERC Orders 888 … and 2000 could propel the wholesale electricity industry only so far towards … competitive markets. Further market reform and standardized market rules and industry procedures were necessary in order to eliminate … discriminatory business practices and structural inefficiencies that have allowed market manipulation and caused the continuation of inefficiencies, such as the discouragement of capital investment in transmission. To this end, the FERC has proposed its [SMD] as a starting point to establish a set of best practices for sound competitive power market conduct and efficient transmission operation and expansion. *Standard Elec. Market Design: Hearing Before the Senate Comm. on Energy and Natural Resources*, (Sept. 17, 2002) (statement of Terry Havrill, Comm'r IL Commerce Comm'n).

1996 trade data will provide the clearest indication of gaps, which *inter alia* the FERC SMD is designed to close, within the dual regulatory system. Data are collected for vertically integrated IOUs, or those providing production, transmission, and distribution services within franchise territories. In 1996, there were 243 IOUs in the continental U.S. I examine the subset of those IOUs that are vertically integrated, classified by the FERC as "majors," and required to file the FERC Form One Annual Report. These criteria are met by 109 IOUs, ten of which are omitted because of missing data. The ninety-nine IOUs are divided into two groups for analysis. The first group of seventy-six cases comprises stand-alone IOUs, and the second group of twenty-three cases comprises IOU affiliates of MHCs. The MHCs are Allegheny Power System, American Electric Power Co., Central and South West Corp., Eastern Utilities Associates, Entergy Corp., General Public Utilities Corp., New England Electric System, Northeast Utilities, and Southern Company *(EIA December 1998)*. Data for the IOUs included in the analysis are provided in appendix one, pages 136-43.

Every vertically integrated IOU has some combination of base-load, intermediate, and peaking production. Typically, efficient base-load capacity from steam-electric plants operates continuously, while inefficient peaking capacity from combustion-turbine plants operates only during times of peak demand. Time-of-day demand patterns and capacity-supply mix will determine the origin and efficiency of marginal production capacity. If an IOU lacks production capacity at any time, it may import electricity from a neighboring IOU with surplus capacity during the same period. For reliability reasons, all vertically integrated IOUs maintain a reserve margin, or a percentage of production capacity beyond that needed to satisfy normal peak demand.

Despite the fungibility of electrons, the mere existence of IOU trade indicates a low elasticity of substitution, or the importing IOU would produce the required electricity itself. Typically a fungible good has a high elasticity of substitution; but electricity cannot be stored, and no substitution can be made if one party has electrons and the other does not at any given time. This low elasticity of substitution is simultaneously a low inter-temporal elasticity of substitution.

In a dynamic, stochastic, two-country economy with complete markets and low elasticity of substitution between domestic and foreign goods, the trade balance and inverse terms of trade will be positively related along an equilibrium path *(Backus 1993, 380-81)*. Similarly, for a stand-alone IOU that operates in its independent interests, size-adjusted trade balance and inverse terms of trade are expected to be positively related along an equilibrium path. The IOU is analogous to country one, with its aggregate trading partners analogous to country two. In practice, the higher the export price relative to import price, the more the stand-alone and self-interested IOU will export, using reserve production capacity. The higher the import price relative to export price, the less the stand-alone and self-interested IOU will export, so it can use its production capacity to serve native demand and still have enough reserve capacity to safely avoid the higher costs of emergency imports.

For a holding-company IOU that does not operate in its independent interests, but in the overall interests of the MHC, the above relationship between size-adjusted trade balance and inverse terms of trade is not expected to apply. In real-time, the substitutability of production capacity and reserves across MHC operating affiliates is equivalent to the substitutability of electricity itself. While electricity has a low elasticity of substitution for a stand-alone IOU, it will have a high elasticity of substitution for a holding-company IOU. Therefore, no positive relationship between size-adjusted trade balance and inverse terms of trade is expected.

To test the above expectations, I examine the relationship between trade balance and inverse terms of trade for the group of seventy-six stand-alone IOUs and the group of twenty-three holding-company IOUs. Trade balance is adjusted for IOU size. The size-adjusted trade balance is calculated as the dollar value of exports minus the dollar value of imports, divided by native production capacity as measured in MW. Inverse terms of trade are defined as average price per kWh for exports divided by average price per kWh for imports *(EIA December 1998)*. As expected, the results show that size-adjusted trade balance and inverse terms of trade are significantly, positively correlated ($r = 0.455$, $p = 0.01$) for stand-alone IOUs, but not for holding-company IOUs.

For a holding-company IOU, trade balance is expected to relate not to terms of trade but to production costs and gross margins, as with discriminatory intra-firm trade and interstate transfer pricing. MHCs are expected to export electricity from their IOUs with low production costs and low allowed gross margins, and import electricity to their IOUs with high production costs and high allowed gross margins. Therefore, two additional variables are introduced: (1) average production cost, and (2) allowed gross margin. Size-adjusted trade balance is expected to be significantly negatively correlated with both average production cost and allowed gross margin.

First, average production cost per kWh is calculated as the IOU's total production cost divided by the total quantity of electricity either self-produced or purchased from IPPs under long-term contract. Vertically integrated IOUs charge their customers for electricity through "bundled" rates that include production, transmission, and distribution components. Customers pay an implicit charge for production, but with bundled rates that implicit charge cannot be directly observed. Therefore, Kahal and Brown *(1997)* estimate each IOU's total production cost from the ground up, which represents what the IOU *should* be charging for production under cost-based ratemaking. Total production cost is equivalent to production revenue requirement (PRR) plus the total cost of electricity purchased from IPPs under long-term contract. The formula for PRR is as follows: *PRR = production rate base x pre-tax rate of return + expenses - ITC gross up.*

PRR is calculated for each IOU using FERC Form One data with an eleven percent return on equity. Applicable state tax rates and a thirty-five percent federal tax rate are used to compute the *pre-tax rate of return* and to "gross up" the annual amortization of investment tax credits (*ITC gross up*). The *production rate base* comprises production plant in service with several additions and subtractions. Additions include fuel stocks, materials and supplies, and an allocation of general plant. Cash working capital is excluded. Subtractions include the depreciation reserve for production plant, an allocation of depreciation reserve for general plant, and an allocation of deferred taxes. *Expenses* include production operation and maintenance (O&M) expense, production-plant depreciation expense, an allocation of administrative and general (A&G) expense, an allocation of general-plant depreciation expense, and an estimation of property taxes paid on non-nuclear plant *(Kahal and Brown 1997).*

Second, allowed gross margin is calculated as average retail revenue per kWh minus the average production cost per kWh calculated above. Under efficient cost-based ratemaking, allowed gross margin should reflect the cost of transmission plus distribution, or the cost of delivery. For each IOU, average retail revenue per kWh is found by dividing total retail revenue by total quantity of retail electricity sold. Total retail revenue reflects the revenue allowed by the state PUC under cost-of-service ratemaking using the basic formula $R=O+B(r)$, where R is the allowed revenue, O is operating expenses, B is the rate base, and r is the rate of return allowed on the rate base. Figures for total retail revenue and quantity of retail electricity sold are available at the state level *(EIA December 1996a, Table 17).* For any IOU with a service territory covering areas in contiguous states, average retail revenue per kWh is found by summing the weighted state averages *(EIA December 1996a, appendix A).*

The results of the analysis indicate the following. For holding-company IOUs, but not for stand-alone IOUs, average production cost is significantly negatively correlated with size-adjusted trade balance ($r = -0.496$, $p = 0.05$), suggesting exports from low-production-cost MHC operating affiliates and imports to high-production-cost MHC operating affiliates. For holding-company IOUs, but not for stand-alone IOUs, allowed gross margin is significantly negatively correlated with size-adjusted trade balance (r = -0.814, p = 0.01), suggesting exports from low-margin MHC operating affiliates and imports to high-margin MHC operating affiliates. As expected, the results of the wholesale trade analysis suggest that discriminatory intra-firm trade allows an MHC to engage in interstate transfer pricing among its operating affiliates. An MHC can circumvent low state revenue caps by importing electricity to its high-production-cost and high-allowed-margin IOUs, and exporting electricity from its low-production-cost and low-allowed-margin IOUs.

The FERC oversees both market-based and regulated wholesale rates for all IOUs, whether stand-alone or within MHCs, to ensure that they are “just and reasonable” and not “unduly discriminatory.” Regulated rates for MHC intra-firm trade, as specified by an Intercompany Interchange Contract (IIC), are reviewed and approved by the FERC. State PUCs, which lack jurisdiction over wholesale rates, are then required to accept and “pass through” these FERC-approved IIC rates when setting retail rates, as affirmed in *Mississippi Power and Light Co. v. Mississippi,* 487 U.S. 354 (1988). Under cost-of-service ratemaking, IOU retail rates are set by the corresponding state PUC when it sets allowed revenue, based primarily on costs associated with using native production to serve native demand, but also incorporating FERC pass-throughs.

For context, I consider a major MHC in the southeastern U.S., the Southern Company. The Southern Company's wholly-owned operating affiliates -- Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and

Power -- provide electric service in a geographically contiguous service area that includes most of the states of Georgia and Alabama, the Florida panhandle, and southeastern Mississippi. The Southern Company's IIC is the operating affiliates' electricity pooling agreement. It provides for the operation of the affiliates' facilities on an integrated basis and establishes wholesale rates for capacity and energy transactions among affiliates. Ostensibly, the IIC is designed to provide the affiliates and their customers the benefits of common planning, joint development, and coordination of operations in the combined service areas. Existing coordination contracts, like the IIC, are unaffected by the FERC Order 888 requirement that IOUs adopt non-discriminatory open-access transmission tariffs.

> [T]he IIC states that coordinated and integrated operations of electric systems … create a power pool to which the operating companies will either sell surplus power not needed to serve territorial load or from which the operating companies will purchase power needed to serve territorial load. Temporary capacity surpluses and deficits are caused by coordinated pool planning and phased construction of generating plants that might produce a mismatch between installed generation and load in the several service areas; errors in forecasting native load; and economic or climatic conditions. The purpose of the IIC is to allocate equitably among the operating companies the monthly surpluses and deficits reported by each of the operating companies. The method used to determine monthly capacity to be purchased or sold … is described as "highly complicated"…. *FERC Docket No. ER89-48-000; 61 F.E.R.C. P61,075 (1993).*

The following excerpt from a FERC administrative proceeding demonstrates the Southern Company's latitude in establishing its own IIC procedures and rates, and how the FERC reviews IIC rates for intra-firm trade. The Georgia-based intervener, Oglethorpe Power Corp. (OPC), has objected to the terms of the IIC devised by the Southern Company (SCSI) and approved by the FERC. As indicated, an intervener has a substantial burden in demonstrating that a FERC-approved IIC is unduly discriminatory and not just and reasonable.

> OPC charges that the IIC methodology used to determine each operating company's monthly obligation to buy or sell capacity surpluses and deficits … is unjust and unreasonable. The intervener alleges that the IIC formula does not differentiate between "surplus" capacity and "excess" capacity; assigns cost responsibility to the operating companies based on "differing load characteristics" that supposedly requires an operating company to purchase capacity not needed to serve territorial load and, in effect, cross-subsidizes or unjustly enriches the seller; discourages development of seasonal load in off-peak months that produces a "negative marketing incentive" and compounds cross-subsidization; and forces operating companies with adequate capacity and reserves to buy pool capacity and to recover costs incurred from the ratepayers….
>
> ….
>
> As the proponent for a change in a Commission-approved technique that deals with the deployment of pool capacity surpluses and deficits, OPC has the burden to demonstrate convincingly that the IIC methodology is unjust and unreasonable and that OPC's methodology is just and reasonable. SCSI … argue for rejection of OPC's proposed treatment of capacity equalization…. OPC has not produced reliable and probative evidence to show the IIC method used to calculate monthly capacity buy-sell requirements is unjust and unreasonable…. [T]here is no reliable and probative evidence to support OPC's position that revisions to the IIC formula will produce just and reasonable results…. When compared with the IIC methodology, the OPC methodology will increase cost of service for four of the five operating companies and reduce cost of service for Georgia Power by over $26 million which will benefit only the ratepayers in the Georgia Power service area, and is not in the public interest. The IIC capacity equalization methodology is just and reasonable. The OPC proposal to revise the IIC on monthly capacity equalization is rejected. *FERC Docket No. ER89-48-000; 61 F.E.R.C. P61,075 (1993).*

The high retail rates and large trade deficit for Georgia Power suggest that Georgia ratepayers subsidize ratepayers in other states served by the Southern Company. The significant Georgia Power imports suggest that surplus and lower-cost electricity from other Southern Company IOUs seeks the higher margins allowed by Georgia's rates. Georgia Power's higher-cost production facilities can then reduce output to avoid variable costs. The result is rationalization of production, interstate transfer pricing through IIC rates, and higher profits for the Southern Company as a whole.

Disaggregating an MHC into its individual vertically integrated IOUs, and further into individual generating units, intra-firm trade under the IIC allows an MHC to optimize its widely dispersed multi-state production portfolio through its internal dispatch system. The incremental kWh required from the transmission grid, at any point in space and time within an MHC service area, is supplied by the MHC generating unit that can provide the incremental kWh at the greatest profitability. To facilitate these intra-firm transfers of electricity, MHC operating affiliates reserve a substantial amount of their "open-access" transmission capability to serve their own production output. With significant intra-firm trade, the MHC can "crowd out" competitive wholesale suppliers and create regional barriers to entry through trade diversion.

Capacity benefit margin (CBM) is transmission capability reserved by IOUs to ensure access to production capacity from interconnected systems. CBM allows a vertically integrated IOU to reduce its installed production capacity below a level necessary to meet reliability requirements in the absence of interconnection. CBM is a key component that goes into the computation of available transmission capability (ATC) in the wholesale electricity markets. ATC indicates how much transmission capability is available to competitive wholesale suppliers. The greater the ATC along a transmission path, the more open are the markets served by that path. *Order Clarifying Methodology for Computing Available Transmission Capability, 88 F.E.R.C. P61,099.*

The FERC requires transmission owners to continuously calculate ATC for their transmission paths and post this information on their Open Access Same-time

Information Systems (OASISs). These OASIS sites, publicly accessible through the Internet, provide information critical to the proper operation of the competitive spot and forward wholesale markets. But the FERC is unable to effectively monitor ATC calculations and other areas where hoarding of transmission capability is possible, and must rely on market participants to initiate and prosecute expensive challenges to incumbent transmission owners.

A vertically integrated IOU also reserves transmission capability, not included in CBM, to serve its native retail load. These reserves are state jurisdictional, invisible to the wholesale markets, and can be used to improperly facilitate wholesale sales from the IOU's own production assets *(Rao and Tabors 2000).* Both stand-alone and holding-company IOUs have the ability to manipulate ATC and "native-load preference," thereby creating entry barriers for competitive wholesale suppliers.

> [D]espite initial market-opening actions by the FERC, progress toward competitive wholesale power markets has been lethargic, and thus, progress in retail market competition has been even more lethargic. Make no mistake: the potential for discrimination and the abuse of market power still exist in wholesale power markets.… [T]ransmission owners still possess enormous incentives to favor their own generation; inconsistent rules governing transmission limit some transactions while lowering costs for others; vertically-integrated utilities continue to possess the opportunity to manipulate transmission availability through control of strategic matters such as [ATC] calculations and capacity set-asides for native load growth projections; and the existence of seams between regions raises costs for inter-regional power flows. *Standard Elec. Market Design: Hearing Before the Senate Comm. on Energy and Natural Resources*, (Sept. 17, 2002) (statement of Terry Havrill, Comm'r IL Commerce Comm'n).

In general, intra-firm electricity trade allows MHCs to (1) use interstate transfer pricing to skirt state revenue caps, (2) optimize profitability of production among its IOUs and generating units, and (3) restrict transmission capability available to competitive wholesale suppliers. The regulatory gaps highlighted here, which give incumbent transmission owners -- and MHCs in particular -- a competitive advantage, are addressed by FERC Order 2000 and the SMD. The proposed RTO structure is designed to close these gaps.

For the Southern Company, transferring control of its transmission system to an RTO would destroy the benefits of intra-firm trade and the IIC. Unsurprisingly, FERC efforts to "push" the Southern Company toward an RTO have been met with strong resistance.

> FERC indicates that it will require all public utilities to join RTOs because "almost all public utilities have joined, or committed to join, an RTO or ISO".... The fact that many public utilities have chosen to participate in RTOs does not justify forcing all jurisdictional utilities to join one. The Commission cannot compel public utilities to join RTOs because "everybody else is doing it." To do so would exemplify the term "arbitrary and capricious".... *White Paper: Wholesale Power Market Platform*, FERC Docket Number RM01-12-000; Issued April 28, 2003 (comment of Southern Company Services at page 15; submitted July 25, 2003).

> [T]he Commission's proposal fails to present a rational basis for the divestiture of control of transmission facilities….
>
> ….
>
> Even assuming the Commission (which has no authority to enforce the antitrust laws) had remedial authority akin to the antitrust laws, the Commission has failed to find the kinds of repeat violations or unlawful combination that warrant the extreme remedy of divestiture. Vertical integration was lawfully undertaken in the electric utility field to enhance output, and was preserved in the enactment of PUHCA.…
>
> ….
>
> The [SMD]'s requirement that a utility must turn over critical aspects of its transmission operations to a third party … would also constitute an unconstitutional taking of property. *Remedying Undue Discrimination through Open Access Transmission Service and Standard Elec. Market Design*, NOPR, FERC Docket Number RM01-12-000; Issued July 31, 2002 (comment of Southern Company Services at pages 20-21; submitted Nov. 15, 2002).

Second, how can regulatory transition losses explain the industry consolidation and divestiture of the 1990s? Regulatory risks for incumbent IOUs include legacy costs that take the form of transition losses in the shift from regulation to competition. These transition losses are costs incurred in the old regulated environment that become unrecoverable sunk costs in a new competitive environment. They can also be defined as the anticipated shortfall in net revenue as a consequence of changes in regulatory policy *(Lupica 2000, 653)*.

In general, sunk costs may be identified as (1) set-up sunk costs, or the initial capital investment; (2) accumulated sunk costs, or the normal costs of doing business; and (3) exit sunk costs *(Clark and Wrigley 1995, 207)*. They have four aspects: (a) recoverability, (b) recurrent financial need, (c) longevity, and (d) transferability. Recoverability refers to the likelihood of being able to retrieve the market value or a discounted value of the initial investment. For a cost to be considered sunk, potential recoverability must be negligible. Recurrent financial need refers to the timing of financial obligations associated with sunk costs. Some sunk costs are a one-time initial investment and have low recurrent financial need, while other sunk costs require recurrent non-recoverable funding. Longevity refers to the time horizon over which a sunk cost has useful value. Transferability refers to the potential for shifting sunk costs to other principals or agents *(Clark 1994, 23-24)*.

Theoretically, in competitive industries sunk costs are ignored when evaluating on-going opportunities. But the residual regulatory compact continues to impose upon incumbent IOUs the mandates of universal service and high system reliability. Exit restrictions mean that many sunk costs associated with the regulatory legacy cannot be ignored, and must still be managed. In the vernacular of regulated industries, these sunk costs are “stranded” and become transition losses in the shift to competition. Stranded costs for vertically integrated IOUs include: (1) QF contracts at above market prices; (2) expenditures not recoverable under competition including deferred investments in power plants, deferred taxes, and retiree benefit costs; and (3) obligations incurred to carry or abandon redundant or obsolete power plants *(Lupica 2000, 668).*

In the shift from regulation to competition, obsolete power plants become a significant source of IOU transition losses. Under traditional cost-of-service regulation, retail price is based on an IOU’s “embedded cost,” or the average cost of producing electricity and delivering it to the consumer, including recovery on investment in plant and equipment with a return on that investment. This bundled price per kWh includes both production and delivery components. Production accounts for about seventy-five percent of the retail price, while delivery accounts for the remainder *(EIA August 1997, 11)*. With bundled pricing, a regulated IOU is guaranteed a reasonable return over its average cost of production and delivery.

With functional “unbundling” under deregulation, production becomes a wholesale component of the retail price. In perfectly competitive wholesale markets, marginal production cost will set the price for the unbundled production component of final retail price. To illustrate, assume a perfectly competitive market within a closed transmission network, where network supply is always adequate to meet fluctuating network demand. Also ignore friction along the network. In this fictional network, the marginal production cost of electricity determines the wholesale spot-market clearing price at all sinks on the network. In the short-run, this marginal production cost is theoretically equivalent to the variable cost, based primarily on the cost of fuel, for the least-efficient generating unit in operation. Therefore, the wholesale spot price for electricity is determined by the marginal production cost of the last and least-efficient generating unit needed to meet the immediate demand for electricity. This spot price is volatile, with the volatility now expected to be absorbed in the marketplace rather than within a regulatory buffer. At non-peak times, the least-efficient on-line base-load generating unit sets market price. At peak times, the least-efficient on-line peaking unit sets market price. Within this market hierarchy, the more efficient the production asset, whether base-load or peaking, the more valuable it is.

Practically, an evaluation of competitive wholesale markets involves network friction and market and network imperfections. Transmission constraints, the physics of electricity, and the regulatory legacy have resulted in loosely connected regional markets. Each of these markets operates in autarchy at least some of the time, with a spot-market clearing price independent of that in neighboring regions. In a competitive environment, the value of a regional production portfolio is influenced by network characteristics and supply-demand conditions within the regional market. Also a factor is whether the production assets are hedged against spot-price volatility and to what extent. Often a producer sells portions of its output at fixed prices under long-term contract.

In regions with high prices, factor adjustment dictates that new low-cost producers will emerge. Upon enactment of EPAct in 1992, factor adjustment began in the form of merchant power-plant investment. With increasing wholesale competition, as more efficient merchant plants are built, long-run marginal production cost for a market region declines, resulting in declining wholesale electricity prices. The difference between long-run marginal production cost for a market region and average production cost for an incumbent IOU provides an indication of the competitiveness of the IOU's legacy production assets. As the supply contribution of new, more-efficient merchant plants increases with competition, the capacity needed from less-efficient IOU plants decreases, potentially creating stranded costs associated with those obsolete plants. Without some form of stranded-cost recovery under deregulation, an IOU would not be able to recover both its fixed and variable costs of production. The unrecoverable fixed costs, imposed by the regulatory legacy, are sunk and become transition losses in the shift to competition.

Deregulation can be quite complex in industries, like the U.S. electricity industry, with a long history of regulation. During the process of restructuring, the regulatory legacy imposes sunk costs and commercial relationships that are very different from those that would have existed in the absence of regulation. When deregulation makes barriers to competitive entry low, like with retail direct-access programs, incumbents normally will seek protection during the transition to allow recovery of some or all of their sunk costs. Therefore, immediate market results may be constrained by prior agreements and sunk costs. Normal market contracting among participants will emerge only as capital previously committed by incumbents, manifested as sunk costs, is amortized *(Meyer and Tye 1988, 274-76).*

In general, transition strategies for sunk-cost recovery include the following: (1) transfer sunk costs to consumers, the government, or other principles or agents. (2) Merge with or acquire a firm in the same industry, which allows for simultaneous internal restructuring and rationalization of production around the most efficient assets. The efficiency benefits of rationalization can finance the restructuring and abandonment of sunk costs. One caveat is that this strategy may raise antitrust and market-power concerns. (3) Merge with or acquire a firm in another industry. This would enable restructuring to be financed by funds flow from the acquired firm, or it could lead to the eventual exit from the original industry. And (4) divest expendable businesses that have significant sunk costs *(Clark 1994, 26-28)*.

IOU transition strategies are developed in close coordination with state legislatures and PUCs, often involving years of discourse with input from numerous stakeholder groups. Unsurprisingly, IOU lobbyists have advocated full stranded-cost recovery under state restructuring programs, but outcomes have been far from certain in both form and substance. Within the context of deregulation, IOUs and regulatory agencies have employed a combination of one or more of the four transition strategies listed above, including (a) direct transfer of sunk costs to consumers or bondholders as "stranded-cost recovery," (b) merger with another IOU, (c) merger with a natural-gas company, and (d) divestiture of power plants *(EIA December 1996b, December 1999, October 2000)*. Each of these transition strategies is described in turn below.

First, some IOUs have been allowed to transfer stranded costs directly to consumers in the form of competitive transition charges (CTCs), or to bondholders in the form of securitization bonds. In general, CTCs allow an IOU to charge retail customers above-market rates until stranded costs are fully recovered, at which time market-based rates control. States employing a CTC include California, Connecticut, Illinois, Maine, Maryland, Ohio, Pennsylvania, Rhode Island, and Virginia. With securitization, the rights to stranded-cost recovery are sold to a third party, usually in the form of securitization bonds. The IOU uses the sale proceeds to pay down debt and equity in an amount corresponding to the amount of estimated stranded costs. Overall stranded-cost recovery is reduced because the carrying cost on the securitization bonds is at a market debt rate, which is lower than the embedded pre-tax cost of the IOU's combined debt and equity capital. Carrying costs are further reduced because, by authorizing issuance of the bonds, states have implicitly assured bondholders that stranded costs will be recovered. States employing securitization for stranded-cost recovery include Connecticut, Montana, New Hampshire, New Jersey, and Texas *(EIA February 2003b)*.

Second, some IOUs have pursued horizontal mergers with other IOUs. These mergers, which require the approval of both state and federal regulatory agencies, began after the start of wholesale deregulation under EPAct but before retail restructuring programs were finalized in most states.

> Since 1992, IOUs have been involved in 35 mergers, and an additional 12 mergers are pending approval. One effect of these mergers is that the size of IOUs is increasing. In 1992, the 10 largest IOUs owned 36 percent of total IOU-held generation capacity, and the 20 largest IOUs owned 58 percent of IOU-held generation capacity. By the end of 2000, the 10 largest IOUs will own an estimated 51 percent of IOU-held generation capacity, and the 20 largest will own approximately 72 percent *(EIA October 2000, xi)*.

Uncertainty about state restructuring programs, combined with the potential for cost reductions and a desire to maintain the competitiveness of legacy production assets, may explain some of the horizontal merger activity. The findings from the wholesale trade analysis, *supra*, suggest why some contiguous vertically integrated IOUs have merged following enabling legislation under EPAct. By merging their multi-state transmission systems, these IOUs can integrate their regional portfolios of power plants *(EIA December 1999)*.

> Cost reduction is not the only reason for companies to merge. A merger of two vertically integrated utilities may result in the consolidation of transmission networks, which enables one firm to control the facilities over which regional power supplies must flow…. Even with mandated open access to the transmission lines, some analysts believe that the owner of the lines can affect the relative success of rival generators and that ownership will increase the strategic position of the company in dealing with competitors *(EIA December 1996b, 92)*.

Third, some IOUs have pursued "convergence" mergers with natural-gas companies. Like horizontal mergers, convergence mergers require the approval of both state and federal regulatory agencies. "In addition to mergers within the electricity industry, IOUs -- seeing growth opportunities in the natural gas industry -- are merging with or acquiring natural gas companies, contributing to what is referred to as convergence of the two industries. In the last 3 years, 23 convergence mergers have been completed or are pending" *(EIA October 2000, xi)*. Strategic justifications for convergence mergers include the following:

> (a) To strengthen wholesale marketing and trading operations.
>
> Deregulation of the electricity and natural gas industries has created spot markets for wholesale electricity and natural gas, as well as markets for buying, selling, and trading financial instruments for risk management…. Many electric utilities and natural gas companies realize that there are similar and related techniques … and are merging to form larger organizations specializing in electricity and natural gas….
>
> ….

> [I]t can help lower administrative and processing costs. It also facilitates arbitrage between electric power and natural gas prices. One of the most frequently cited reasons for a convergence merger is that the gas company's experience in marketing and trading can be transferred to an electric company that is relatively new to working in competitive markets and commodity trading. The gas industry has been deregulated since the 1980s, and over that time surviving gas companies have developed skills and experience *(EIA December 1999, 29).*
>
> (b) To diversify products and expand retail markets.
>
> Most electric utilities believe that to remain competitive they need to offer more products and services to their retail customers. State-designed customer choice programs, which allow retail customers to select their energy suppliers, motivate utilities to differentiate their products from their competitors' products. One strategy to accomplish this is to merge with a local gas distribution utility and offer both electricity and natural gas services to customers. The idea of "one-stop shopping" appeals to some customers, and combined marketing and delivery systems can also help reduce the utility's billing, metering, and other administrative costs *(EIA December 1999, 33).*
>
> (c) To access fuel for merchant power plants and product diversification.
>
> Electric utility mergers with upstream or midstream natural gas companies position the new company to benefit from the growing demand for natural gas stimulated by the projected growth in gas-fired power plants across the country.…
>
> ….
>
> Electric utilities that own upstream and midstream natural gas resources will be positioned to compete for customers in growing natural gas markets brought on by the increase in demand for gas-fired plants. Also, by owning upstream and midstream gas resources, a company can expand its range of products and services and build a marketing strategy focused on a customer's total energy needs *(EIA December 1999, 33-35).*

Fourth, IOUs are divesting power plants in coordination with various state restructuring programs. "IOUs are divesting power generation assets in unprecedented numbers. Since late 1997, IOUs collectively have divested or are in the process of divesting 156.5 gigawatts of power generation capacity, representing about 22 percent of total U.S. electric utility generation capacity" *(EIA October 2000, xi).* Justifications for this transition strategy include (1) divestiture eliminates vertical market power for incumbent IOUs and facilitates the transition to a competitive environment; and (2) the settled auction value for the power plants, compared to book value, establishes a market-based measure for stranded-cost recovery *(EIA October 2000, 106).*

> States that are opening the electric market to retail competition view the separation of power generation ownership from power transmission and distribution ownership as a prerequisite for retail competition. Some States have passed laws requiring utilities to divest their power plants.… California, Connecticut, Maine, New Hampshire, and Rhode Island are examples….
>
> ….
>
> In other States that have passed electricity industry restructuring legislation, the requirements for unbundling are not always clear and vary from State to State. In some instances, the [PUC] may encourage divestiture to arrive at a quantifiable level of stranded costs for purposes of recovery during the transition to competition…. [M]any times the PUCs are not explicit in their unbundling requirements, leaving it to the utility to propose a method that satisfies the PUC's unbundling objectives and satisfies the strategic and economic objectives of the utility. The utility prepares a company restructuring plan which may include selling its assets or, alternatively, transferring its assets to an unregulated subsidiary company. Negotiation and compromise between the PUC and the utility are part of the process of finalizing the plan *(EIA October 2000, 106).*

Plus, some small IOUs are divesting power plants because they cannot compete effectively in the production sector, and choose to focus exclusively on transmission and distribution services *(EIA December 1999, 42).*

> As a business strategy, a few utilities have decided to sell their power plants, indicating that they cannot compete in a competitive power market.… [T]hese companies concluded that at their present level of power generation capacity, they are too small to compete effectively in a competitive power market. Small companies cannot achieve the economies of scale that larger power generation companies achieve, making it difficult for them to compete in the new market place *(EIA December 1999, 42).*

Third, what are the implications of the overlapping jurisdictional framework for state and regional market design? A transaction-costs analysis may be used to examine the interface between the U.S. electricity industry and dual regulatory system, as well as commercial relationships among industry participants. Regulatory transaction costs reflect interactions between the industry and regulatory environment, while commercial transaction costs reflect interactions between buyers and sellers. Under a comparative institutional perspective, the efficient industry economizes on regulatory transaction costs. Policymakers, regulatory agencies, and industry participants will seek boundaries between state and federal institutions that economize on the transaction costs of regulating and running the electric system. Common regulatory transaction costs include (a) costs associated with regulated firms' weakened efficiency incentives relative to markets, (b) the bureaucratic or administrative costs of regulation to society, and (c) lower investment and increased financing costs from risks of regulatory delay, uncertainty, and re-contracting *(Williamson 1979, 1985)*.

The term "re-contracting" invokes principles from contract law, and refers to an unexpected change in the traditional compact between the industry and regulatory environment. Contract law is often separated into three classifications: (1) classical contract law, (2) neoclassical contract law, and (3) relational contracting. First, classical contract law is characterized by formal and discrete contracting with highly predictable remedies in the event of nonperformance. The emphasis is on legal rules, formal documents, and self-liquidating transactions. Second, neoclassical contract law, unlike classical contract law, can accommodate longer-term contracts under conditions of uncertainty. To manage transaction costs, these types of contracts require a different governance system than classical contracts, which often means adding third-party arbitration. Third, relational contracting arises when the pressure to sustain ongoing relations removes various subject areas from the classical and neoclassical frameworks. Examples are collective bargaining and government regulation, both of which are "contracts" of high duration, complexity, and uncertainty. Unlike with neoclassical contracting, where the reference point for contractual adaptation is the original agreement, the reference point for relational contracting is the entire relationship as it has developed over time. Governance systems for relational contracting, like the contracts themselves, are highly complex *(Williamson 1979, 236-38)*.

A specialized governance system based on relational contracting, such as rate-of-return regulation with periodic review, is often needed for an industry with natural-monopoly characteristics.

> [R]egulation may be described contractually as a highly incomplete form of long-term contracting in which (1) the regulatee is assured an overall fair rate of return, in exchange for which (2) adaptations to changing circumstances are successively introduced without the costly haggling that attends such changes when parties to the contract enjoy greater autonomy *(Williamson 1985, 347)*.

This governance system reduces risk for industry participants while facilitating adaptive and sequential decision making. But in industries that are not natural monopolies, where transaction-specific investments are negligible, the case for rate-of-return regulation is weak *(Williamson 1979, 257-58)*.

Vertical de-integration of the U.S. electricity industry is premised on the belief that the (a) production sector, including wholesale supply and trade, is no longer a natural monopoly and can operate within a competitive merchant structure under market-based classical contracting; and (b) transmission and distribution sectors remain natural monopolies and must continue to operate under rate-of-return regulation. Thus far, vertical de-integration has encountered substantial market imperfections and volatility.

> [R]estructuring proposals advanced in the past were premised on the expected near-term success of competitive wholesale electric markets operating in a world populated with many energy traders and [IPPs]. That certainly has not happened…. Revelations in recent months have made it more clear that the results of these deregulation efforts have been disastrous in the West and questionable elsewhere…. [C]haracteristics … are fundamentally different from those of other industries. These characteristics include, among others, the fact that electricity is a real-time product produced and consumed simultaneously, cannot be stored, is a necessity of modern life, and has no reasonable substitute. Delivery of electricity requires hard-wire connections, making this function a natural monopoly that must be regulated in some manner. Further, it is a complex network industry and all parts -- generation, transmission and distribution -- must work together. This situation necessitates planning to ensure optimum use of individual facilities and the network, as well as associated infrastructure investments. All of these unique characteristics make it very difficult to displace regulation with a purely competitive market in the electricity industry. *Oversight on Elec.: Hearing Before the Senate Comm. on Energy and Natural Resources*, (March 27, 2003) (statement of Alan Richardson, Pres. and CEO, Am. Pub. Power Ass'n).

The separation of production and delivery, and production's radical shift from relational to classical contracting, has been unexpectedly disruptive. In response, state and federal deregulation are now on more cautious paths of gradual transition to competitive markets. During this transition, an ongoing relational contract between the industry and regulatory environment allows for adaptive and sequential decision-making. A strong relational contract, combined with an appropriate governance system, will lower regulatory transaction costs and reduce the uncertainty associated with idiosyncratic transactions, complex processes of deregulation, and the risks associated with restructuring *(Olson 1997).*

The restructuring process must be flexible while continually seeking efficient boundaries between state regulation and federal regulation; and between (1) production, which is potentially competitive, and (2) delivery, which maintains monopoly characteristics. The task for legislatures, regulatory agencies, and industry participants is to jointly form a governance system that supports a healthy restructuring process. The FERC SMD proposal is a step in that direction. With its bold and controversial proposal, the FERC has taken the lead in promoting state, regional, and federal discourse. Active and ongoing discourse surrounding the SMD proposal will encourage the formation of both a functional governance system and viable restructuring process.

The SMD, based on the RTO concept, is intended to promote wholesale markets by (a) reducing uncertainty, (b) clarifying the respective roles of state and federal regulatory agencies, (c) lowering commercial and regulatory transaction costs, (d) eliminating discriminatory market access, and (e) encouraging infrastructure investment to improve efficiency and reliability. In accomplishing these objectives, RTOs address both vertical and horizontal market issues.

First, the RTO structure de-integrates production from delivery. Vertical separation of the production and delivery functions reduces discriminatory market access and increases efficiency by promoting competition in the production sector. As independent operators of the transmission grid, RTOs will operate under private regulation with standard rules, while the FERC limits its role to market monitoring and oversight. Consumers will benefit from rationalization of production across the regional network, competition in the production sector, reduced regulatory transaction costs, and improved market transparency.

> [C]reation of RTOs is the single most effective way of achieving a vibrant, competitive electric market. RTOs that are fully independent of market participants can ensure non-discriminatory operation of the transmission facilities under their control. RTOs have FERC-approved market monitors, implement FERC-approved market mitigation plans, and conduct long-range planning all for the protection of customers. RTOs can perform economic dispatch over large geographic areas that will ensure the selection of least-cost generators. Finally, RTOs can offer organized markets and one-stop shopping that reduce transaction costs, provide transparent market rules and allow the opportunity for price discovery. *Oversight on Elec.: Hearing Before the Senate Comm. on Energy and Natural Resources*, (March 27, 2003) (statement of Nora Mead Brownell, Comm'r, FERC).

Second, RTOs address horizontal market issues by promoting efficient market signals across broad areas and lowering commercial transaction costs. Electricity delivery entails significant transaction costs, both natural and man-made. The natural transaction costs of delivery, including line loss and loop flow, are based on the laws of physics and can never be completely eliminated. However, man-made transaction costs can be reduced with good planning and coordination. These transaction costs include information gaps, market "seams" or barriers, transmission constraints, and cumulative or "pancaked" transmission tariffs. Minimizing the impact of these costs is important for regional markets to function properly, and properly functioning markets will encourage industry participants to engage in activities that increase market efficiency, improve reliability, and lower consumer prices.

> The Midwest ISO believes that it is correct to analyze transmission and energy markets regionally. Electrons cross borders. Power lines cross state lines. Actions in one state can significantly affect customers in another…. A properly organized regional energy market offers benefits to all users of the grid. It offers transparent pricing. It offers improved peak resource management. It offers more … flexibility for market participants to meet their needs. It offers the increased efficiency of an interconnected transmission system. Finally, markets offer enhanced reliability. *Oversight on Elec.: Hearing Before the Senate Comm. on Energy and Natural Resources*, (March 27, 2003) (statement of James P. Torgerson, Pres. and CEO, Midwest Indep. Transmission Sys. Operator).

Without RTOs, horizontal transaction costs may lead to small wholesale markets characterized by one dominant supplier or a tight oligopoly. Broad RTOs will reduce horizontal transaction costs, thereby transforming small markets into larger markets. Despite the efficiency benefits of large markets, the FERC's RTO proposal has been resisted by some states. This resistance often reflects a desire that the RTO structure include more flexibility on scope and configuration.

> [I]t must be recognized that electricity markets have developed based on regional differences. These regional markets have different population densities, unique transmission system characteristics, disparate local fuel sources, differing dispatch protocols and generation ownership. These all reflect unique regional characteristics of geography, and economic development. *Financial Condition of the Elec. Market: Hearing Before the Senate Comm. on Energy and Natural Resources,* (March 4, 2003) (statement of David Svanda, Comm'r, MI Pub. Serv. Comm'n and Pres., Nat'l Ass'n of Regulatory Utility Comm'rs).
>
> We need to distinguish between those aspects of SMD that should be common throughout all regions, and those aspects which can vary among the regions. We need to calibrate the timing and the substance to the facts within each region. This type of a regional approach would better accommodate the realities of regional diversity in geography and fuel sources; differences in demographic and economic factors; differences in cultural and governmental institutions; and the existence of different regulatory approaches. *Standard Elec. Market Design: Hearing Before the Senate Comm. on Energy and Natural Resources,* (Sept. 17, 2002) (statement of Sandra Hochstetter, Chairwoman, AR Pub. Serv. Comm'n).

Other state resistance may simply reflect the nature of the dual regulatory system. First, state PUCs may resent the intrusion upon their traditional jurisdictional authority.

> I recognize that FERC has the statutory responsibility to regulate wholesale electric markets and to remedy unduly discriminatory access to the transmission system…. I am also cognizant of my responsibility as a state regulator…. Many of my colleagues in the state regulatory community and I are very concerned that FERC … is attempting … to inappropriately and unnecessarily extend its jurisdiction into areas that should remain the province of state regulators under the dual regulatory regime that, for the most part, serves our citizens well. *Standard Elec. Market Design: Hearing Before the Senate Comm. on Energy and Natural Resources,* (Sept. 17, 2002) (statement of Sandra Hochstetter, Chairwoman, AR Pub. Serv. Comm'n).

Second, as local regulatory agencies, state PUCs may believe they are better able than the FERC to understand and respond to the needs of the local public.

> [I]nstitutions engaged in electricity supply and the regulation of electricity services should be accountable … to the public that relies on those essential services. Under our current system there are strong links of accountability that run from the citizen-ratepayer to the state regulator to the regulated utility. This "triangle" of accountability works to ensure that citizens receive the electricity they need and utilities receive the revenues they need. The proposed rule seriously degrades the public accountability of critical electricity institutions. *Standard Elec. Market Design: Hearing Before the Senate Comm. on Energy and Natural Resources,* (Sept. 17, 2002) (statement of Marilyn Showalter, Chairwoman, WA State Utilities and Transport Comm'n).

Third, in some states, retail electricity prices are lower than the national average, giving PUCs little incentive or justification for restructuring. For example, the state of Kentucky has an abundance of low-cost electricity produced from native coal.

> Kentucky has the lowest average electricity costs in the nation.… FERC seeks to force fundamental changes to the way Kentucky's utilities operate without any probative evidence that there is a need for such changes, and without any showing that customers served by these utilities will see significant benefit from them. Certainly the first goal of all regulation should be to do no harm. *Remedying Undue Discrimination through Open Access Transmission Service and Standard Elec. Market Design*, NOPR, FERC Docket Number RM01-12-000; Issued July 31, 2002 (comment of the KY Pub. Serv. Comm'n, submitted Nov. 15, 2002).

One concern from low-cost states is that their native electricity will be diverted to higher-cost states within the RTO, resulting in higher local prices. The FERC responds by encouraging the use of long-term contracts that lock in low prices and keep native output within the state.

> One of the most widely-voiced concerns about the proposal is that it could cause cost-shifting between states -- that low-cost states will see electricity prices rise as competition lets high-cost states buy up the cheap power. We don't believe that will happen and have made several parts of our proposal clear in this regard. The proposed rule does not abrogate existing contracts for power or transmission; it encourages load-serving entities in low-cost states to keep their existing low-cost power at home under long-term contracts and/or retail state regulation. *Standard Elec. Market Design: Hearing Before the Senate Comm. on Energy and Natural Resources,* (Sept. 17, 2002) (statement of Pat Wood, Chairman, FERC).

Additional resistance to RTOs comes from incumbent IOUs, which traditionally have exercised substantial influence over state PUCs. Their resistance may stem from fear of being unable to wield the same influence over RTOs *(Koch 2000)*. Usually an industry and regulatory agency have a formal adversarial relationship, but sometimes an industry *wants* regulation and "captures" the regulatory system. Under the principles of capture theory, the industry acquires regulation through the political process for its own benefit. An industry may use the political process to gain (1) a direct subsidy of money, (2) competitive barriers to entry, (3) policies that impact substitutes or complements, or

(4) price fixing *(Stigler 1971, 4-6)*. The industry that seeks regulation goes to the appropriate seller, the political party, which accepts votes and resources as payment *(Stigler 1971, 12)*. Under the principles of capture theory, regulation is a normal good subject to the forces of supply and demand.

For example, the Southern Company has resisted joining an RTO, arguing in part that it would require investment in new production capacity to offset the loss of capacity-sharing among operating affiliates. The wholesale trade analysis, *supra*, suggests that Georgia consumers are disadvantaged by capacity sharing under the Southern Company's IIC. Ironically, the Georgia PUC, perhaps captured by the Southern Company, opposes the RTO concept even though it likely would benefit Georgia ratepayers.

> FERC has not demonstrated that discrimination in access to transmission facilities exists in Georgia or, for that matter the entire Southeast, or that FERC's proposed SMD represents a cost-effective, least intrusive, more appropriate solution…. The regulated utilities in Georgia … remain vertically integrated, which we believe has served customers well in the absence of a deregulated retail electricity market. Breaking up this structure by the formation of an RTO to handle the transmission services could result in additional costs to ratepayers. We would like to see the evidence and proof first from FERC that there has been "undue discrimination" … before concluding whether FERC's proposed SMD solution is appropriate. *Remedying Undue Discrimination through Open Access Transmission Service and Standard Elec. Market Design*, NOPR, FERC Docket Number RM01-12-000; Issued July 31, 2002 (comment of the GA Pub. Serv. Comm'n, submitted Nov. 15, 2002).

Continued delay in finalizing the SMD creates problems of its own. Uncertainty about the eventual specifics of RTO formation leaves restructuring stalled and discourages beneficial capital investment. In the wholesale electricity markets, capital investment will be made only if investors can expect an attractive risk-adjusted return.

Markets lacking transparency are fraught with risks that may discourage investment in production and transmission assets.

> Energy markets need clear rules and certainty…. [T]he investment community views the energy industry as being in constant flux, including even the implementation of existing rules. Together, the FERC, the regions, and the states need to set market rules that have staying power and can be relied upon when making investments. *Oversight on Elec.: Hearing Before the Senate Comm. on Energy and Natural Resources,* (March 27, 2003) (statement of David S. Svanda, Pres., Nat'l Ass'n of Regulatory Utility Comm'rs).

For example, investment in production assets may be deterred by the risk that a future change in transmission pricing will render an investment uneconomic, and by the risk of self-dealing by firms that own both production and transmission assets. The self-dealing risk is proportional to the number of firms that own transmission lines between a potential production site and major sources of demand. Without the protections of an RTO, a transmission owner is likely to have the incentive and ability to engage in self-dealing that reduces the value of a competitor's production assets by precluding the competitor's access to markets at critical times *(Pierce 1999)*. Notably, the certainty afforded by a FERC-approved RTO in the Midwest is credited with bringing infrastructure investment to the state of Michigan.

> [C]onsistent federal and state policies that support investment in energy infrastructure must continue. Complementary policies serve as the cornerstone for promoting consistency that is necessary to build confidence in the energy industry. These policies can lead to standard business practices that all industry participants can rely on. At the same time, they are critical to providing transparency and reducing market risks…. My own home state of Michigan provides an example of how such policies can induce investments in electricity infrastructure markets. Our two largest electric utilities were formerly fully integrated, owning generation, transmission, and distribution facilities. Recently, these two Michigan utilities have unbundled, or have chosen to divest, not their generation, but their transmission assets to non-affiliated entities.…

> [T]he purchasing companies are pursuing a competitive business model for transmission additions and expansions in a business environment with consistently supportive federal and state policies.... It is interesting to note that both of these transmission sales, almost one billion dollars of new investment, were made possible in part because of consistent state and federal policies that encourage participation in the new regional Midwest Independent System Operator (MISO). The stability of regional open access rules and the promise of transparent and vibrant Midwest transmission markets no doubt encouraged investors to commit substantial capital to an otherwise stagnant utility sector. Several other transmission-owning MISO participants have also committed to additional transmission construction that probably would not have occurred without the establishment of this FERC approved [RTO]. *Financial Condition of the Elec. Market: Hearing Before the Senate Comm. on Energy and Natural Resources,* (March 4, 2003) (statement of David Svanda, Pres., Nat'l Ass'n of Regulatory Utility Comm'rs).

Despite the call for a "standard" market design, the FERC recently bowed to state pressure and acknowledged the relevance of inherited state and regional differences. In its April 2003 White Paper, which reflects stakeholder comments to the SMD proposal, the FERC invites further discussion and compromise while continuing to stress the objectives of interregional coordination and market integration.

> Regional operation is critical for both reliability and efficiency because power flows freely throughout regional grids. Order No. 2000 said "the scope and configuration of the regions in which the RTOs are to operate will significantly affect how well they will be able to achieve the necessary regulatory, reliability, operational and competitive benefits." However, in the Final Rule we will allow flexibility on scope and configuration….
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> ….
>
> RTOs and ISOs are developing methods of interregional coordination that allow separate control, but a single market from the customer's perspective. Therefore, in the Final Rule we will not require ISOs to meet the scope and regional configuration requirement. However, all must actively pursue interregional coordination between RTOs and ISOs, including the elimination of the payment of multiple access fees for transactions that cross ISO and RTO borders. *White Paper: Wholesale Power Market Platform*, FERC, April 28, 2003.

Finally, what regulatory lessons emerge from the market correction associated with California, Enron, and the Blackout of 2003?

California

Under California's failed restructuring program, inadequate production reserves contributed to supply shortages, high wholesale electricity prices, and opportunities for market "gaming" in 2000 and 2001. California gaming might have been reduced with stronger state and federal oversight and stricter enforcement of market rules. Plus, from the outset, steps could have been taken to prevent harmful bidding behavior.

> [W]hen California sold off approximately 18,000 MW of fossil-fuel generation capacity owned by PG&E, SCE, and SDG&E … it was done without an accompanying provision that the new owners agree to sell back to these three firms at fixed price a large fraction of the … output from these units in long-term contract.… These mandatory buy-back forward contracts sold along with the generation units are typically called "vesting contracts".… If each supplier knows that other suppliers have vesting contracts and are eager to supply at least their forward contract obligations from their own units, then all suppliers will have strong incentives to bid very close to their marginal cost of production for their forward contract obligation. This aggressive bidding … will set market prices very close to competitive levels in all but the highest demand periods.… [I]f suppliers have little or no forward contract obligations, their incentive to bid substantially in excess of the marginal cost … can be much greater.… [For] suppliers that own a portfolio of generation units, one can immediately see the tremendous increase in the incentive to bid in excess of marginal costs during certain system conditions caused by the lack of vesting contracts.… [A]ny increase in the market price could be earned on virtually all of the energy produced by these suppliers. *Asleep at the Switch -- FERC's Oversight of Enron Corp.: Hearing Before the Senate Comm. on Governmental Affairs,* (Nov. 12, 2002) (statement of Frank A. Wolack; Prof. of Economics, Stanford Univ.; and Chairman, Market Surveillance Comm., CA ISO).

The California "crisis" was exacerbated by industry participants that created local shortages and price spikes by withholding production and jamming California's overloaded transmission lines at select locations.

> As is becoming increasingly clear … the observed scarcity of electricity during the crisis period was caused by market participants creating an artificial shortage of electricity that would enable them to sell the electricity they did provide at substantially higher prices.… This artificial scarcity during the crisis period also allowed suppliers to charge substantially higher prices for any electricity delivered under any forward financial contract with a delivery date in the future less than the time necessary to bring a substantial amount of new generating capacity on-line.... *Asleep at the Switch -- FERC's Oversight of Enron Corp.: Hearing Before the Senate Comm. on Governmental Affairs,* (Nov. 12, 2002) (statement of Frank A. Wolack; Prof. of Economics, Stanford Univ.; and Chairman, Market Surveillance Comm., CA ISO).

The FERC has jurisdiction over wholesale electricity markets, while California has jurisdiction over its retail markets. Because California's aggressive restructuring program incorporated both wholesale and retail deregulation, FERC and California officials worked together to design the program in a demonstration of "cooperative federalism."

> The restructuring program developed and implemented in California was the outcome of a close cooperative relationship between FERC and California officials -- they called it "cooperative federalism." FERC approved California's new wholesale market institutions before they went into operation in April 1998. Both federal and state officials enthusiastically took credit for the restructured wholesale and retail electricity markets they were creating. However, as problems emerged, and especially when the market exploded during the summer of 2000, FERC was not as closely involved in solving the problems as it should have been. The cooperative relationship … quickly deteriorated into a hostile relationship that focused on finger pointing and sloganeering rather than on finding practical solutions. *Economic Issues Associated with the Restructuring of Energy Industries: Hearing Before the Senate Comm. on Governmental Affairs,* (June 13, 2001) (statement of Prof. Paul L. Joskow, Dir., Center for Energy and Environmental Policy Research, MIT).

During the California crisis of 2000 and 2001, the FERC had responsibility to assert its jurisdictional authority to ensure that wholesale electricity prices were just and reasonable. For example, California agencies, with no direct authority over wholesale markets, were unable to stop the export of electricity to other western states. In a breach of the California market rules, these exports skirted in-state price caps and often were "ricocheted" back into California as higher-priced uncapped imports. Despite requests from state authorities, the FERC did little to address high California electricity prices until June 2001, when it imposed wholesale price caps across the western states.

In being slow to act, the FERC attributed the California crisis to a fundamental supply and demand imbalance that would correct itself. High prices were explained as normal market signals that would encourage investment in new production and transmission infrastructure. But the FERC ignored the simple truth that new electricity infrastructure takes months or years to construct, and meanwhile conditions would remain dire.

> The long time lag necessary to construct new generation capacity can result in long periods of significant market power in an electricity market.… Even under the most optimistic scenarios, the time from siting a sizable new generating facility to producing electricity from this facility can range from 18 to 24 months. This estimate does not include the time necessary to obtain the permits needed to site the new facility, which can sometimes double the time necessary to bring the new plant on line. For this reason, once market conditions arise which allow existing generating facilities to exercise substantial amounts of unilateral market power … these market conditions are very likely to persist for a long enough period of time to impose substantial economic hardship on consumers. *Economic Issues Associated with the Restructuring of Energy Industries: Hearing Before the Senate Comm. on Governmental Affairs,* (June 13, 2001) (statement of Frank A. Wolack, Prof. of Economics, Stanford Univ.).

The FERC has re-examined its role since the events of California, and through the SMD proposal is advocating substantially greater involvement in the design and oversight of wholesale electricity markets. Under new leadership, the FERC now recognizes that rigorous oversight and occasional intervention in the nascent electricity markets are necessary to promote market development, stability, and sustainability.

> [An] RTO provides effective market monitoring and has clear market rules designed to protect customers.… Experiences in California have shown the consequences of poorly designed markets and inadequate generation, transmission and demand response. Moreover, they demonstrate the need for before-the-fact market power mitigation and ongoing market monitoring. Some areas also have experienced "seams" problems where differences in design between regions create artificial barriers to trade which raise costs, limit customer supply choices, and create opportunities for exploitation. *White Paper: Wholesale Power Market Platform,* FERC, April 28, 2003.

Consistent regulatory intervention in the "deregulation" process can reduce the volatility often associated with abrupt market liberalization, and a more gradual and interactive approach to deregulation appears to be gaining favor *(Wessel 2003)*.

> The new wholesale market that began operating in California in April 1998 is not an "unregulated" market that has been operating smoothly for decades under the guidance of the "invisible hand" of competition. Rather, it is a newly created market that most knowledgeable people expected would have at least some problems that would need to be fixed and over which FERC had and has continuing regulatory authority and responsibility.
>
> ….
>
> The fact that market performance problems have occurred and mitigation measures have been necessary in all of the newly created wholesale markets should not be surprising.… Ongoing market reforms and regulatory "mitigation" initiatives designed to remedy serious market performance problems should be an *expected* feature of the *process* of creating efficient competitive wholesale electricity markets. Price caps, bidding rules, cost-based contracts and a variety of other mitigation mechanisms have been used or are being used in most new wholesale markets in the U.S. as short run mechanisms to protect electricity consumers from serious market imperfections until longer term fixes can be developed, introduced, and evaluated. *Economic Issues Associated with the Restructuring of Energy Industries: Hearing Before the Senate Comm. on Governmental Affairs,* (June 13, 2001) (statement of Prof. Paul L. Joskow, Dir., Center for Energy and Environmental Policy Research, MIT).

The ability of California suppliers to drive up prices by withholding production highlights the importance of substantial production reserves. Price volatility must be absorbed in the wholesale markets so it will not affect retail consumers, which requires an abundance of production capacity under the control of numerous competitive suppliers. California would have benefited if the legislature and PUC had encouraged the successful construction of new power plants and transmission lines prior to launching the state's restructuring program.

In the early 1990s, the best examples of states with low production capacity were California and Texas, both of which restructured their wholesale and retail markets in the past decade. Much new production capacity has been built in Texas during this period; but little in California, where onerous siting and environmental regulations have discouraged power-plant construction. California still lacks adequate production capacity, while Texas now has excess capacity and has retired several obsolete plants *(Reuters 2003b)*.

In theory, where the regulatory environment is favorable to new investment, regulatory transaction costs associated with greenfield investment will be low and can be internalized. Conversely, where the regulatory environment is unfavorable, regulatory transaction costs will be high, making cost internalization difficult and discouraging capital investment *(Russo 1992)*. Texas has historically had a friendlier regulatory environment than California, and in Texas the transition to competitive wholesale and retail markets has been relatively smooth.

Legacy structures associated with transmission patterns and constraints make some states inherently better positioned for restructuring than others. For example, in Texas the transmission grid was intentionally kept separate from the rest of the U.S. grid to avoid federal jurisdiction. Texas wholesale and retail deregulation has been successful in part because the state's transmission system has always been geographically isolated, and was designed to stand alone. Electricity produced in Texas remains in Texas. This isolation has allowed the Texas PUC to exercise more influence over geographically discrete wholesale and retail markets.

In addition, most Texas power plants are fueled by natural gas, which is plentiful within the state. California power plants also are fueled largely by natural gas, but the gas must be shipped by interstate pipeline, much of it from Texas. Unusually high natural-gas prices at western delivery points were a significant contributor to California's high electricity prices in 2000 and 2001. The contrast between the Texas and California restructuring experiences points to the need for well-designed markets that account for local characteristics and resources, whether state or regional, with Texas having an intrinsic advantage over California. Similarly, how RTOs incorporate unique regional characteristics will factor into their success or failure.

Notably, the Texas PUC Chairman responsible for restructuring was Pat Wood, who left to join the FERC in June 2001 and is now its Chairman. The following testimony, which Wood made shortly after joining the FERC, summarizes Texas restructuring and foreshadows the SMD proposal and its implementation process.

> Prior to my appointment to the FERC two weeks ago, I was Chairman of the [PUC] of Texas. Due to the wholly intrastate nature of the grid … my colleagues … and I had a role overseeing the development of the wholesale markets … that is very similar to the role FERC plays.… [L]ike other state [PUCs], we also regulated the retail rates and services of all [IOUs] serving Texas customers. In implementing Congress' 1992 mandate to open up wholesale electric markets, the FERC must focus first on the sufficiency of infrastructure and on the market rules governing a competitive market. Infrastructure is a broad concept, encompassing … generation plants … demand-side resources and the power delivery grid. Oversight of the infrastructure is a shared state-federal responsibility. Development and enforcement of market rules is primarily a FERC responsibility, but it, too, involves state [PUCs]. Maintenance of sufficient infrastructure and oversight of the market is an ongoing job. In Texas, the market has been opened in stages. First, in 1995, the Texas Legislature and Governor Bush fully opened the electric generation market to non-utility companies. In 1996, the [PUC] mandated the nation's first [ISO] to alleviate market power concerns…. In 1997 and 1998, the [PUC] adopted standard rules and tariffs to speed development of generation (both large and small-scale) and transmission. In 1999, the Texas Legislature and Governor Bush directed the [PUC] to open the retail sales markets to competition by January 1, 2002. Immediately following passage of the 1999 legislation, we focused on adapting the … wholesale market structure to one accommodating competitive retail sales, as well as establishing the parameters for retail competition. In 2000, the [PUC] established a Market Oversight Division within the agency to serve as a market cop…. Having the full span of activity under one regulatory roof gave Texas the comfort that its transition to a fully competitive market will be beneficial for its citizens. From that Texas experience, I feel it is absolutely crucial that the FERC be a trusted and capable partner with our sister state commissions as they move to a more competitive model. No state will venture into a competitive future if it does not believe that its market opening efforts will be backed up by its federal partner. Vigilant, and collaborative, oversight of the various regional power markets is the most significant role the FERC will play in coming years. *The Role of the FERC Associated with the Restructuring of Energy Industries: Hearing Before the Senate Comm. on Governmental Affairs,* (June 20, 2001) (statement of Pat Wood, Comm'r, FERC).

Enron

To begin, the following three testimony excerpts put the Enron demise in historical perspective. The U.S. electricity industry's Fordist mode of regulation began with the collapse of the Insull Trust, which helped prompt the PUHCA and FPA reforms of the 1930s. Exactly how a similar collapse of the Enron Corporation influences the current mode of regulation remains to be seen.

> Seventy years ago a pioneering electric and natural gas firm collapsed. The bankruptcy, the largest one in U.S. history at the time, destroyed the retirement savings of millions of Americans…. I am speaking of the Insull Trust. Sam Insull … built a huge empire known for its lack of transparency. Even given the weak financial reporting standards of the time, Insull's structure was shrouded in secrecy. Ownership relationships were so tangled that it took twenty years to untangle the web of interlocking directors and pyramided debt and equity financings. The collapse of the Insull Trust created an enormous public outcry. Reforms directly traceable to the collapse are the genesis of our current regulatory structure…. Seventy years later we are re-enacting the same drama with Enron. Not only are the financial details frighteningly similar, but we are realizing that our regulatory framework has failed to protect investors and consumers from exactly the same abuses. *Impact of Enron Collapse on Energy Markets: Hearing Before the Senate Comm. on Energy and Natural Resources,* (Jan. 29, 2002) (statement of Robert McCullough, Managing Partner, McCullough Research).

> On December 2, 2001, Enron, then ranked as the nation's seventh largest company, filed for federal bankruptcy protection amid allegations of far reaching financial and other fraud. Enron's collapse left thousands of employees without jobs and with severely diminished retirement savings and erased billions of dollars of shareholder value. Perhaps most significantly, it triggered a crisis of investor confidence in U.S. financial markets -- and a concomitant crisis in ratepayer and investor confidence in the energy markets. Enron's meltdown has had effects that have reverberated through the energy sector as well as other parts of the U.S. economy, and its consequences continue to be felt today. *Asleep at the Switch -- FERC's Oversight of Enron Corp.: Hearing Before the Senate Comm. on Governmental Affairs,* (Nov. 12, 2002) (statement of Majority Staff).

> [T]he electric industry's credit situation is the worst in over 70 years, with half the industry rated below investment grade. Today, a limited number of banks are controlling the lending market at a time when $25 billion needs to be refinanced in 2003 alone. The equivalent of one year's electric industry revenues, $250 billion in market capitalization, has been lost to the industry. The equity value of the merchant power sector alone has dropped from $145 billion to under $10 billion. The combined capital expenditures of regulated and deregulated electricity companies, as a fraction of their revenues in the 1990s, was 12%. This is half the expenditure rate during the Depression and World War II. *Financial Condition of the Elec. Market: Hearing Before the Senate Comm. on Energy and Natural Resources,* (March 4, 2003) (statement of David Svanda, Pres., Nat'l Ass'n of Regulatory Utility Comm'rs).

Under 1990s federal deregulation, open-access requirements allowed Enron to foster trading liquidity by "piggybacking" on the infrastructure investments of incumbent natural-gas and electric utilities. A first-mover advantage and appetite for risk established Enron as the primary market maker. As the counterparty on one side of every trade that it processed, Enron was able to collect vast amounts of real-time data about energy markets, which it used in trading for its own book. Enron traders mined proprietary data to find arbitrage opportunities, and in early years profited substantially by arbitraging inefficient natural-gas and electricity markets.

In late 1999 Enron introduced Enron Online, which increased trading volumes by supplanting fax and telephone trading with Internet trading. Between 1999 and 2000 energy trading volumes more than doubled, with Enron's revenue -- which reflected trading volumes -- reaching roughly $101 billion in 2000, placing it number seven on the Fortune 500. Enron's substantial market share stemmed from its access to capital and high risk-tolerance. As the primary market maker, Enron accepted financial risks that other traders would not accept, and posted offerings others would not post. In exchange for its risk-taking, Enron experienced high trading volumes, which meant more proprietary data for Enron's trading book. In addition to high trading volumes, Enron wanted volatility because it was naturally "long" volatility. The greater the price volatility for energy commodities, the more arbitrage opportunities there were.

As a market maker, Enron needed to maintain strong financial liquidity to offset weak physical liquidity in electricity and other markets. Large working capital requirements and an unrealistic growth strategy encouraged Enron management to leverage and "stretch" the balance sheet, often using off-balance-sheet vehicles to hide debt financing. These vehicles were also used to inflate earnings and operating cash flow, help keep an investment-grade credit rating, maintain a low cost of capital, and boost the stock price.

By 2000 Enron was severely over-leveraged and, in trying to meet its cash needs, speculated aggressively in the western electricity markets. Prior to the spring of 2001 the FERC had been largely absent from the California crisis, and Enron may have operated under the assumption that the FERC was captured. Intervention by the California PUC and FERC in spring and summer 2001 reduced electricity prices throughout the western U.S., prompting margin calls and a large cash exodus from Enron's trading book. This cash outlay, combined with revelations about accounting improprieties and improper related-party transactions, contributed to the financial liquidity crisis and bankruptcy several months later.

Enron's collapse sparked a market correction in the entire merchant electricity sector, evidenced by a massive 2002 restructuring in response to accounting, credit, and market-manipulation concerns. Market forces have pushed merchant energy traders away from speculative financial trade and toward asset-based physical-only trade. Credit for merchant energy traders has become very tight, making financial trade difficult, especially in long-term contracts. Increasingly, large banks with strong balance sheets and credit ratings are stepping in to fill the gaps *(Reuters 2003a)*. Going forward, speculative financial trade by these well-capitalized banks will improve market liquidity and efficiency.

In a related vein, the activities of Enron and other merchant energy companies may have manipulated wholesale price signals and erroneously influenced factor adjustment. Numerous power plants were scheduled for construction in the coming years, many of which were cancelled as wholesale electricity prices declined following Enron's collapse *(Smith 2003b)*. Over time, this industry correction will allow for more accurate price signals under stricter regulatory oversight. Perhaps the single most important lesson from the Enron collapse is that deregulation of a large economic sector may result in an unforeseen need for greater or different regulation elsewhere, and regulatory agencies must not work in isolation. In fact, the failure of Enron and other energy traders has prompted calls for greater oversight of energy commodities by the Commodity Futures Trading Commission (CFTC).

> FERC and the CFTC have yet to figure out their respective roles in an increasingly sophisticated energy market that involves both physical energy products and commodities futures and other derivatives -- whether the issue involves oversight of online trading platforms or some other aspect of the market. Notably, FERC does not even have interagency information or regulatory coordination agreements with either the CFTC or the SEC, nor with other key regulatory or financial agencies. *Asleep at the Switch -- FERC's Oversight of Enron Corp.: Hearing Before the Senate Comm. on Governmental Affairs,* (Nov. 12, 2002) (statement of Majority Staff).

The Blackout of 2003

Because electricity production usually is not located at the place of consumption, imbalances arise within the transmission network. Imbalances are caused in part by (a) the physics of electricity, (b) production-capacity deficits, and (c) transmission constraints. To avoid system-critical transmission failures, including brownouts and blackouts, it is necessary to have spatial and temporal balance between production and consumption along the network. Through the correct mix of base-load, intermediate, and peaking plants, with sufficient production and transmission capacity and proper coordination, the supply curve must be able to follow the demand curve at all network sinks. Maintaining this delicate system balance requires real-time coordination among control centers located across the U.S. Transmission coordination involves more than 6,000 generating units within approximately 130 control areas, most of which are operated by individual utilities *(Revkin 2003)*.

> The Nation's transmission grid is an extremely complex machine…. The total national grid delivers power from more than 850,000 megawatts of generation facilities. The grid is operated by utility staff at some 130 round-the-clock control centers. The large number of these centers -- some relatively small -- has been the focus of much attention in post-Blackout analysis and discussion. When a generating facility or transmission line fails, the effects are not just local. Instead, the problem often has widespread effects and must be addressed by multiple control centers. *Keeping the Lights On -- The Fed. Role in Managing the Nation's Elec.: Hearing Before the Senate Comm. on Governmental Affairs,* (Sept. 10, 2003) (statement of Pat Wood, Chairman, FERC).

Prior to the east coast blackout of 1965, utilities collaborated on an ad-hoc basis to maintain the reliability of the U.S. electrical grid. Under state and federal pressure following the 1965 blackout, utilities cooperatively established the North American Electric Reliability Council (NERC). The approximately 130 control areas are each part of one of ten NERC regions *(see figure five, page 148)*. As a non-government entity, NERC is a volunteer organization with no authority to enforce reliability rules. Concerned that the profit motive might encourage utilities to circumvent rules and sacrifice grid reliability, the NERC itself now supports the transfer of its responsibilities to a government agency with enforcement authority.

> Recent changes in the electric power business tend to leave more matters affecting reliability outside the exclusive control of the local utility. Electricity trading patterns are becoming increasingly regional and reliability is now more likely to be affected by the actions of parties that may be several states away. This means that it is more important than ever to have clear reliability rules that are observed by everyone. Unfortunately, NERC lacks authority to enforce its rules. Because changes in the industry increased both the incentive for, and frequency of, NERC rule violations, NERC now advocates making transmission reliability oversight a government function so that interstate … reliability rules can be enforced uniformly. *The Impact of Elec. Industry Restructuring on System Reliability: Hearing Before the Senate Comm. on Governmental Affairs,* (June 28, 2001) (statement of Kevin A. Kelly, Dir. of the Div. of Policy Innovation and Communication, FERC).

Under the present system, control-area operators within each NERC region voluntarily coordinate to maintain reliability, dispatching power plants and exchanging electricity as necessary to balance the grid. With the introduction of competition under federal deregulation, this voluntary system is beginning to break down.

> [A]s the electric industry restructures the voluntary system will not serve us well for the future. Here's why: (1) The grid is now being used in ways for which it was not designed. (2) There has been a quantum leap in the number of hourly transactions, and in the complexity of those transactions. (3) Transmission providers and other industry participants that formerly cooperated willingly are now competitors. (4) Rate mechanisms that in the past permitted utilities to recover the costs of operating systems reliably are no longer in place, or are inadequate given increased risks and uncertainties. (5) The single, vertically integrated utility that formerly performed all reliability functions for an area is being disaggregated, meaning that reliability responsibilities are being divided among many participants. (6) Some entities appear to be deriving economic benefit from bending or violating the reliability rules. (7) Construction of additional transmission capacity has not kept pace with either the growth in demand or the construction of new generating capacity, meaning the existing grid is being used much more aggressively. *The Impact of Elec. Industry Restructuring on System Reliability: Hearing Before the Senate Comm. on Governmental Affairs,* (June 28, 2001) (statement of David N. Cook, Gen. Counsel, N. Amer. Elec. Reliability Council).

Perhaps the most important component of grid reliability is transmission capability. With inadequate transmission capability, critical system imbalances are more likely to occur. Traditionally, states have had siting authority for transmission lines; but as part of the RTO and SMD debates, the FERC now advocates federal involvement.

> The amount of new transmission added in the past two decades has consistently lagged behind growth in peak demand.… Construction of high voltage transmission facilities is expected to increase by only six percent … during the next ten years, in contrast to the expected twenty percent increase in electricity demand and generation capacity.… I believe that state-by-state siting of such transmission superhighways is an anachronism that impedes transmission investment and slows transmission construction…. This is an area where a regional perspective is needed. *Oversight on Elec.: Hearing Before the Senate Comm. on Energy and Natural Resources,* (March 27, 2003) (statement of Nora Mead Brownell, Comm'r, FERC).

The complexity of regional transmission planning and siting, which impacts multiple states, supports regional management of these functions. Presumably, RTOs will promote regional objectives as opposed to individual state objectives. Plus, RTOs can use market signals gathered from their market-monitoring activities to guide the location of new transmission investment.

> [T]he decision as to whether a particular area is congested is an extremely complex task. In PJM, we have found that the slightest changes in power flows can cause an area that is congested one day to not be congested the next. Moreover, not all congestion is bad. One need weigh, through an appropriate cost/benefit analysis, whether the cost to clear congestion that is causing increased costs but does not threaten reliability is outweighed by the cost to remedy that congestion.… [T]he decision as to whether or not an area is congested and needs relief should be determined by the marketplace relying on technical information provided by the regional transmission organization or the system operator. *Oversight on Elec.: Hearing Before the Senate Comm. on Energy and Natural Resources,* (March 27, 2003) (statement of Phillip G. Harris, Pres. and CEO, PJM Interconnection).

The FERC, with legislative support from Congress, wants to formally give reliability authority to RTOs. Making RTOs responsible for reliability, under FERC oversight, takes transmission-siting authority away from the states and makes it part of a regional planning process. Plus, empowering RTOs to enforce reliability rules gives these rules “teeth” that the NERC cannot provide. In fact, a regional perspective to transmission siting and reliability is already imbedded in the RTO market-monitoring function, which straddles the line between commercial and reliability practices.

The reliability of the grid can be bolstered through regional planning and operation of the transmission system, such as regional planning of new facilities; greater investment in infrastructure; and better methods of monitoring and managing transmission flow in order to relieve congestion. The Commission has underway several initiatives to address these issues, including: (1) promoting the formation of independent regional organizations with clear wholesale market rules to promote an efficient, reliable wholesale marketplace; (2) authorizing incentive rates for new infrastructure, including innovative technologies; and (3) identifying problems in the transmission infrastructure....

….

Currently, there is no direct federal authority or responsibility for the reliability of the transmission grid. The [FPA] contains only limited authorities on reliability.… [T]he Commission must ensure that all rates, terms and conditions of jurisdictional service … are just, reasonable and not unduly discriminatory.... These sections generally have been construed as governing the commercial aspects of service, instead of reliability aspects. However, there is no bright line between "commercial practices" and "reliability practices." *Keeping the Lights On -- The Fed. Role in Managing the Nation's Elec.: Hearing Before the Senate Comm. on Governmental Affairs*, (Sept. 10, 2003) (statement of Pat Wood, Chairman, FERC).

Chapter Five: External Economies and the Regulatory Environment

This chapter addresses the second sub-question introduced in chapter two: for the U.S. electricity industry, how do technology and the formal regulatory framework meet with the external economies of vertical de-integration and flexible capital accumulation? The first related question concerns electricity trade: how and within what regulatory framework can electricity trade, both physical and financial, improve market efficiency and stability? A second related question addresses the restructuring of electricity production: how have regulatory and technological changes influenced locations and patterns of electricity production? The final related question addresses DG and distributed real-time pricing: what are the potential roles of DG and distributed real-time pricing in a restructured marketplace, and how does the regulatory environment influence their deployment?

First, how and within what regulatory framework can electricity trade, both physical and financial, improve market efficiency and stability? According to conventional wisdom, utilities and IPPs have become commodity producers *(Winje 1997)*, with the distinction that they produce a physical commodity, electrons, that must be consumed as produced. Typically, commoditization occurs as an industry or technology matures, resulting in near-perfect competition and undifferentiated products. In contrast, electricity commoditization dovetailed with wholesale deregulation and the growth of electricity trade following EPAct of 1992.

For most commodities, delivery extends the act of storage down through the distribution channel. For some weightless commodities, including financial instruments and electricity, delivery is accomplished over wires. But unlike financial commodities that can be "stored" and then delivered over the Internet at readily identifiable transaction costs, non-storable electricity must be simultaneously produced and delivered within a complex physical network.

> The two most significant characteristics of electricity are that it cannot be easily stored and it flows at the speed of light. As a result, electricity must be produced at virtually the same instant that it is consumed, and electricity transactions must be balanced in real time on an instantaneous spot market. Electricity's real-time market contrasts sharply with the markets for other energy commodities, such as natural gas, oil, and coal, in which the underlying commodity can be stocked and dispensed over time to deal with peaks and troughs in supply and demand.
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> ….
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> The laws of nature, rather than the law of contracts, govern the power flows from electricity suppliers to consumers. By nature, electricity flows over the path of least resistance and will travel down whatever paths are made available to it. Because the suppliers and consumers of electricity are interconnected on the transmission grid, the voltage and current at any point are determined by the behavior of the system as a whole (i.e., impedance) rather than by the actions of any two individual market players *(EIA October 2002, 51).*

In financial commodities including currencies, equities, and interest-rate instruments, the Internet and central exchanges have made geography largely irrelevant *(O'Brien 1992)*. Both buy/sell orders and the underlying financial instruments are transmitted over the Internet, linking counterparty communication directly with commodity delivery. But for electricity and other physical commodities, the Internet will not serve as both the transaction medium and delivery conduit. Physical delivery is separated from the originating transaction by the effects of space. Even electricity derivatives, which take a financial form, must allow for the contingency of physical delivery. By guaranteeing either physical or financial delivery, derivatives traders are still required to address logistics, and geography remains relevant.

For electricity trade, physical transaction costs reflect the network relationship between a transaction source and sink, and are managed separately from the electrons themselves. The distance between the network source and sink is quantified as a location basis; while loop flow and parallel-path flow, which reflect network traffic characteristics, are managed with congestion fees. By pricing location basis and network congestion, electricity traders attempt to strip away the effects of space, leaving a fungible good and removing the spatial impediments to electricity commoditization. But these transaction costs will be volatile, as the optimal network path and traffic characteristics change. It is this real-time logistical component that keeps geography relevant, despite that electrons themselves are fungible. For electricity, the impacts of space and time cannot be fully financialized, and placing a financial or virtual network over the physical network does not make geography disappear *(Clewlow and Strickland 2000)*.

Physical electricity trade is primarily regional, because of network limitations and the physics of electricity. If local production and consumption do not match at any time, utilities and IPPs engage in bilateral physical trade with outlying counterparties or transact in the spot and forward markets at regional trading points. These regional markets, encompassing competing portfolios of power plants, are discrete networks that loosely interconnect at interregional trading hubs. Interregional trade will occur when it is economic -- because of production mix, capacity limitations, transmission constraints, or fuel costs -- to expand the boundaries of the regional market. In theory, with interregional trade and factor adjustment, convergence of long-run marginal cost across regions will occur, resulting in market integration. But the two prerequisites for market integration, liquidity and price discovery, remain poorly developed for electricity.

> Theoretically, there are more than 166 potential hubs in the United States where electricity could be exchanged; however, more than 85 percent of power trading historically has been conducted at only a dozen trading points.… As a result of system interactivity, limited transmission capability between areas, and local congestion, there is only a weak relationship between pricing at the major hubs and pricing at nearby locations. In addition, it is not clear that the level of competition among traders is sufficient to ensure that arbitrage opportunities will be taken at minimum cost to ultimate buyers and sellers.
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> ….
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> Price information is a critical part of market mechanisms. Price information allows transactions between distant parties and gives market participants opportunities to anticipate future prices and to act on those anticipations by hedging.… Only about 10 of the largest hubs have large, liquid spot markets with readily transparent electricity price data.… More than 100 hubs do not supply current market price data *(EIA October 2002, 53-54).*

Many electricity transactions are financial-only trades with no physical delivery of electricity. Like any fungible commodity, electricity can be “financialized.” Any one electron is like another, just like one dollar is like another, but dollars can be transferred among parties more easily than electrons. If actual delivery of electricity is not required in a particular transaction, it is preferable instead to transfer dollars in the form of an electricity “derivative.” Active financial trade in electricity derivatives -- which include forwards, options, and swaps -- promotes the liquidity, price discovery, and arbitrage necessary for market efficiency and integration. However, barriers to the creation of an efficient electricity-derivatives market are substantial.

> - The physical supply system is still encumbered by a 50-year-old legacy of vertical integration.
> - Electricity markets are subject to Federal and State regulations that are still evolving.
> - As a commodity, electricity has many unique aspects, including instantaneous delivery, non-storability, an interactive delivery system, and extreme price volatility.
> - The complexity of electricity spot markets is not conducive to common futures transactions.
> - There are also substantial problems with price transparency, modeling of derivative instruments, effective arbitrage, credit risk, and default risk *(EIA October 2002, 47).*

By the mid-1990s, despite the barriers, energy traders and marketers -- beginning with Enron -- had introduced derivatives to the electricity markets. On the positive side, electricity derivatives allow hedging, which provides certainty for both producers and consumers. For example, derivatives allow for the creation of electricity supply contracts over numerous future periods. These forward contracts work as financial hedges and risk allocation mechanisms among parties. Plus, forward contracts in the form of power purchase agreements (PPAs) often provide the certainty needed for the funding of new infrastructure.

On the negative side, weak arbitrage discipline can actually distort electricity markets. A fundamental premise behind derivatives is that the underlying asset can be held or stored. For example, a forward price will never exceed the cost of purchasing the commodity today and holding it over the period of the forward contract. The ability to hold a commodity promotes price discovery and provides arbitrage discipline in the absence of liquidity. The fact that non-storable electricity cannot be “held” in the conventional sense constitutes a fundamental disconnect in applying derivatives concepts to electricity *(Clewlow and Strickland 2000)*.

While physical electricity trade is important to balance the grid, and financial trade in electricity derivatives is useful for hedging, speculative financial trade has done little to improve market efficiency, especially while Enron was the primary market maker and largest speculator. The illiquid over-the-counter electricity markets do not produce independent forward price curves extending beyond the very near term. Therefore, energy trading companies often created their own price curves used in their "mark-to-market" or "mark-to-model" valuations for long-dated derivatives.

By the late 1990s, poor liquidity and weak arbitrage discipline had encouraged the creation of "proprietary" forward price curves with little basis in reality. These forward curves were used to set values for illiquid electricity derivatives. By 2001, grossly inflated values created an industry-wide valuation "bubble" that eventually burst, starting with the collapse of Enron.

> [T]he circumstances of Enron's bankruptcy have raised specific questions about the effect of accounting for forward trades in electricity.… Selling electricity for future delivery is essential for efficient operation of electric markets.… Where there is a transparent liquid market for longer-term commodity contracts, mark-to-market accounting is used to recognize and disclose the financial impact of such transactions. However, where forward markets are not as liquid and prices are not as transparent, there are greater uncertainties as to the proper market valuation and accounting for such transactions. Thus, the absence of transparent market prices could raise concerns about improper manipulation of anticipated prices that could distort financial reporting and disclosure. Questions have been raised regarding Enron's accounting for the income from such transactions and its treatment of the risks and valuation of the underlying trades. In a related vein, questions have been raised whether the exemption of forward energy trades from CFTC regulation contributed to Enron's problems by giving it a greater opportunity to take advantage of illiquid markets.
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> ….

> [T]he "energy" area of greatest concern is the transparency of financial reporting and disclosure in thinly traded electricity markets. The ultimate cure for this is to initiate measures to promote more liquid trading markets. In the electricity context, this would involve enhancing our transmission infrastructure, moving toward standardized power markets with efficient transmission pricing, facilitating independent regional transmission organizations and establishing more liquid "hubs" for the delivery and trading of power. *The Effects of the Bankruptcy of Enron on the Functioning of Energy Markets: Hearing Before the House Comm. on Energy and Commerce*, (Feb. 13, 2002) (statement of David Owens, EVP, Edison Electric Institute).

For electricity derivatives, liquidity can introduce the market discipline needed to counterbalance weak arbitrage discipline. Liquid financial markets generate accurate price signals and promote efficiency in the physical spot and forward markets. The SMD debate contemplates RTOs with central exchanges that (1) provide physical and financial liquidity, and (2) promote efficient price discovery.

> [W]ithout a market-based system that works hand in hand between the financial market and the physical market, there will be little meaningful information to report. This would be the equivalent of disbanding the New York Stock Exchange but still requiring brokers to report individual bilateral transactions. One would still not have the organized marketplace that provides open, transparent prices that are verifiable. One need only look at the problems found recently in bilateral trader reporting of natural gas prices in trade publications to see why an approach without an actual exchange is problematic. We believe that RTOs should operate day ahead and real time spot markets. *Oversight on Elec.: Hearing Before the Senate Comm. on Energy and Natural Resources*, (March 27, 2003) (statement of Phillip G. Harris, Pres. and CEO, PJM Interconnection).

Critical to the production of accurate price signals is an independent financial exchange not subject to manipulation by any one market player. Enron Online, which was a "one-to-many" exchange, generated a large portion of the electricity price signals in 2000 and 2001. As a market maker and counterparty on one side of every trade, Enron had the opportunity to influence price signals in the illiquid electricity markets. In contrast, a “many-to-many” exchange is less susceptible to manipulation and creates more robust markets.

> Enron’s collapse suggests that it was a mistake to allow a significant market buyer or seller to be a market maker without oversight. As a market maker, Enron created information asymmetry by requiring all buyers to buy from Enron and all sellers to sell to Enron. As a result, even though Enron aided the market by providing more price information and liquidity, Enron was also in a position to consistently be among the first to know about most forward power markets transactions.... Enron Online may have allowed the company to gain an advantaged information position.… [S]uch information asymmetries can create a serious market flaw. *Impact of Enron Collapse on Energy Markets: Hearing Before the Senate Comm. on Energy and Natural Resources,* (Jan. 29, 2002) (statement of Lawrence Makovich, Senior Dir. and Co-head, N. Am. Energy Group).

> Traditional exchanges, like the NYSE and the NYMEX, determine price by matching the buy and sell orders of many traders in a many-to-many trading format. In contrast, EnronOnline uses a one-to-many trading format, where an Enron affiliate is always on one side of each energy transaction, either as a seller or a buyer. The price of a commodity or derivative on EnronOnline is determined when a buyer or a seller accepts an offer or bid price posted by an Enron trader. In the wake of Enron's downfall, the many-to-many platforms … have helped to fill the void, and create a more robust market by reflecting the bid and offer values of myriad different energy buyers and sellers. *The Effects of the Bankruptcy of Enron on the Functioning of Energy Markets: Hearing Before the House Comm. on Energy and Commerce,* (Feb. 13, 2002) (statement of Pat Wood, Chairman, FERC).

Electricity market making is becoming the domain of established financial intermediaries with healthy balance sheets, namely large banks that operate under strong regulatory oversight *(Reuters 2003a)*. These banks will offer financial hedges to offset volatility risk for buyers and sellers while engaging in limited derivatives speculation.

Merchant electricity producers will use physical trade and financial hedges to maximize the value of their production assets while avoiding risky speculative trade. Trading will be done either bilaterally or on many-to-many exchanges with strong oversight by the FERC and CFTC. As this framework matures, the U.S. electricity industry will receive more accurate and stable price signals to guide new investment and promote market efficiency and integration.

Second, how have regulatory and technological changes influenced locations and patterns of electricity production? The traditional U.S. electricity industry was vertically integrated, under a Fordist structure of large-scale production and control over the value chain, to maximize economies of scale and internalize transaction costs. Restructuring has origins in the energy shocks and dramatic new production technologies of the 1970s, which unsettled the structure of underlying costs and prices. With emerging competition and the formation of markets associated with deregulation, the traditional utility functions are de-integrating into distinct product and service components, with geographic implications. On the product side, IOUs and IPPs are spatially and operationally diversifying their production assets. On the service side, IOUs are consolidating their transmission and distribution systems into larger contiguous regional monopolies.

Electricity producers facing competitive risks associated with deregulation may employ various risk-management techniques. For example, they may seek a diversified production configuration that optimally relates revenue to volatility risk. Principles of risk management from the field of corporate finance are useful in understanding how spatial diversification of production has advantages in terms of the risk-adjusted flow of revenue. Modern portfolio theory (MPT) and the capital asset pricing model (CAPM) *(Sharpe 1964, Lintner 1965)* suggest that the risk of any investment, whether a new acquisition or continuing to hold an existing asset, should be evaluated with respect to the risk profile of the firm's entire portfolio of assets. Efficient portfolios either minimize risk for a given expected return or maximize return for a given level of risk. Under MPT, a firm will want to diversify its portfolio, thereby reducing the overall risk profile of the assets. MPT supports multi-plant spatial diversification as a strategy to reduce risk, as measured by profit instability, of corporate holdings *(Hanink 1984, Cromley and Hanink 1985)*.

In the present context, a portfolio is a "basket" of power plants. Risk as defined within CAPM has two dimensions: (1) systematic risk, or the sensitivity of returns to movements in the broad economy or sector; and (2) unsystematic risk, sometimes called residual or diversifiable risk, which is the sensitivity of returns specific to the structure and organization of the production portfolio. According to CAPM, it would be logical for the producer wishing to reduce unsystematic risk to hold multiple power plants located in different geographic markets and generating revenue flows with a low covariance of risk *(Sharpe 1964, Lintner 1965)*.

Neoclassical location theory most often focuses on the production of non-perishable goods that can be physically stored and delivered to places of consumption. Of particular interest is the relationship between inputs and outputs, including relative distances and transportation costs. The optimal location for the industrial plant is where the sum of input and output costs is least. If input costs and economies of scale outweigh output costs, production will tend to be large-scale and central, located near input sources in a cost-minimizing configuration. If output costs outweigh input costs and economies of scale, production will tend to be smaller and decentralized, located near output sinks in a profit-maximizing configuration *(Hayter 1997, 111-36)*.

The unique properties of electricity encourage dispersed production near places of consumption, as is typically the case with perishable goods. Electricity is instantly perishable, making the spatial relationship between production and consumption quite strong. The input for electricity production varies and includes water, nuclear, and fossil fuels. Hydroelectric plants must be located at the water source. But discretionary siting of nuclear and fossil plants usually places them close to major places of consumption where output costs are low. Nuclear plants invariably are central base-load plants with economies of scale. For fossil plants, the economic tension between output costs and economies of scale influences the regional composition of large central base-load plants versus small decentralized peaking plants.

For electricity production, the relative importance of economies of scale versus output costs varies along the demand curve. In off-peak periods, economies of scale from base-load plants are more important; while during peak demand periods, output-cost minimization from peaking plants is more important. To maintain system reliability, peaking plants must be able to respond very quickly to demand spikes at dispersed locations. Minimization of transmission costs and system failures, the two primary output costs, encourages small and decentralized peaking plants located close to places of consumption.

Since the 1970s, smaller and decentralized base-load production has become more common because of (a) an expanded natural-gas network, (b) improved mechanical efficiencies of combustion turbines, and (c) the introduction of cogeneration and combined-cycle technologies. Natural gas is relatively inexpensive in terms of clean-burning heat content, transportation costs, and availability. Gas is injected into a pipeline and, as long as pressure is maintained, can be extracted at any point along the pipeline. With the emergence of cogeneration technologies in the 1970s, it became economically efficient to produce electricity with small gas-fired plants using combustion turbines. With cogeneration, waste heat from the combustion turbine is used for other purposes, usually the creation of steam.

Two common configurations exist for gas-fired combustion-turbine power plants *(see figure six, page 149)*. One is simple cycle, meaning that a combustion turbine in a stand-alone configuration rotates a generator that produces electricity. The waste heat from the turbine is exhausted into the air. These simple-cycle plants have a low thermal efficiency and operate only during times of peak electricity demand. In competitive markets these peaking plants turn on and off in response to variations in the local spark spread, which is the price difference between natural gas and electricity expressed in common thermal units. The spark spread indicates whether it is profitable for a particular combustion turbine, with a particular thermal efficiency, to convert natural gas to electricity at any given time.

The other common configuration for a gas-fired combustion turbine plant is a combined-cycle configuration, which uses cogeneration to increase the overall efficiency of the plant. Here, the waste heat from the combustion turbine is captured and used in a boiler to create steam. The steam is then used to drive a separate steam-turbine generator. Because two electric generators operate rather than one, more electricity is produced with the same amount of fuel. Many modern combined-cycle plants have efficiencies approaching those of coal-fired or nuclear power plants, and are often base loaded *(EIA October 2000, 42)*. The efficiencies of base-load combined-cycle production undermine the economies-of-scale justification for having large central power plants under the umbrella of a regulated IOU. The reduction in scale economies allows more decentralized production by merchant producers, with smaller power plants located closer to places of consumption.

> Restructuring has been sustained primarily by technological improvements in gas turbines.… These improvements … have recast economies of scale in electric power generation technologies. No longer is it necessary to build a 1,000-megawatt generating plant to exploit economies of scale. Combined-cycle gas turbines reach maximum efficiency at 400 megawatts, while aero-derivative gas turbines can be efficient at scales as small as 10 megawatts. Indeed from 1996 through 1998, gas-fired and gas- and oil-fired capacity brought on-line was almost two-thirds of the total. The average capacity of these units was 65 megawatts *(EIA October 2000, 44-45)*.

In theory, new combined-cycle merchant power plants will economically displace the least-efficient base-load IOU plants. Simple-cycle merchant plants also have become more efficient in recent years and may displace the least-efficient IOU peaking plants. IPPs have the advantage of geographic diversity and can build merchant plants in areas with the greatest expected returns. Some IOUs are using unregulated affiliates to geographically diversify their own production, by building or acquiring EWGs outside their native territories. Through extraterritorial investment in the form of EWGs, IOUs can diversify their production portfolio beyond legacy regional markets and regulatory environments. Diversification might include a combination of legacy and greenfield plants; base-load and peaking plants; natural-gas, coal-fired, and nuclear plants; and plants located in numerous geographic locations *(Chen and Merville 1986; Clark and Wrigley 1997, 291-95)*.

Geographic patterns of industrial restructuring are influenced by the legacy structure of relative costs and prices, which create both (a) barriers to entry, representing the commitment of incumbent firms, and (b) barriers to exit, representing the inherited configuration of production and "locational inertia."

> [E]conomic events are assumed to be only a proximate (in time) cause of restructuring; macroeconomic events such as price and demand shocks do matter, but their significance is mediated through the structure of relative costs and prices. Restructuring -- the deliberate reconfiguration of a firm's or industry's costs and prices -- may be triggered by economic events, just as those events may be a pretext to implement restructuring *(Clark 1993, 15-16).*

Contestability theory addresses the character of entry and exit barriers. For example, economies of scale have frequently been considered an impediment to entry. However, contestability analysis shows that economies of scale do not necessarily permit excessive profits or prices, or any of the other manifestations of market power. This is true even when scale economies make an industry a natural monopoly. It is sunk costs rather than economies of scale that are significant *(Bailey and Baumol 1984, 111-12).*

The need to sink capital into a new enterprise imposes a difference between the incremental costs and risks faced by an entrant and an incumbent. The incumbent's capital is already committed and exposed to whatever risks industry participation entails. In contrast, an entering firm must take the corresponding amount of liquid capital and turn it into a frozen risk-bound asset. The incremental cost for a potential entrant includes the full amount of sunk costs, which is a bygone to the incumbent. Plus, the potential entrant must be willing to accept the risk of failure. Profitable entry can be achieved only if the profits expected in the event of success outweigh the unrecoverable losses in the event of failure *(Baumol and Willig 1981, 418).*

According to contestability theory, two types of industries exist: (1) those that are highly contestable, called type one; and (2) those that are poorly contestable, called type two. In type-one industries, potential new competitors operating at lower costs and prices can serve the market of incumbent firms by using similar production methods and techniques. The incumbent firms are unable to quickly match the prices of new competitors. In these industries, sunk costs are low and long-run costs can be spread across a high-volume output, allowing new competitors to easily enter and leave. Conversely, in type-two industries sunk costs are high and long-run costs are substantial, with few opportunities for short-run raiding *(Clark 1993, 14).*

A perfectly contestable market is one where (a) a firm can enter and then, if it chooses, exit without losing any of its investment. With freedom of entry and exit, incumbent prices that offer profits to new entrants will not be sustainable. And (b) no sunk costs exist. It is not the total amount of capital required for entry that is important, but the amount of capital that is sunk. Entry involving highly mobile capital, even if it is substantial, may be followed by easy exit. Even if exit from an industry as a whole is difficult, mobility of capital may permit easy entry into and exit from particular markets within the industry. The smaller the portion of invested capital that is sunk, the more contestable the industry will be *(Bailey and Baumol 1984, 113-14)*.

The electricity industry is a low-contestability type-two industry, with significant barriers to entry in the form of sunk-cost requirements. Under deregulation, regulatory agencies are tasked with weakening the entry barriers imposed by these sunk costs. This may be done by (1) requiring open access to existing sunk facilities, as with the transmission infrastructure; or (2) isolating the sunk investments, leaving a relatively contestable part of the industry's operations to be controlled by market forces while the portion with substantial amounts of sunk capital remains regulated *(Bailey and Baumol 1984, 123-24)*. State and federal regulatory agencies are using both approaches simultaneously by (a) isolating and continuing to regulate transmission and distribution systems, (b) requiring open access to the transmission infrastructure, and (c) subjecting electricity supply, including production and trade, to market forces. Deregulation is designed to promote contestability by lowering entry barriers and transaction costs for merchant producers, traders, and suppliers.

Transaction costs associated with the development of new production capacity include (1) direct and indirect costs from interaction with state and federal regulatory agencies; (2) "NIMBYism" or "not-in-my-backyard" resistance; (3) network properties, which may not be favorable to the development of a production facility at a particular location; (4) siting and interconnection requirements; and (5) fuel procurement. The FERC, with its July 2003 Final Rule on large generator interconnection, has taken a step toward lowering transaction costs for power-plant construction.

> The Commission to date has addressed interconnection issues on a case-by-case basis.… [M]any industry participants remain dissatisfied with existing interconnection policy and procedures. With the increasing number of interconnection related disputes, it has become apparent that the case-by-case approach is an inadequate and inefficient means to address interconnection issues. Interconnection plays a crucial role in bringing much-needed generation into the market to meet the growing needs of electricity customers. Further, relatively unencumbered entry into the market is necessary for competitive markets. However, requests for interconnection frequently result in complex, time consuming technical disputes about interconnection feasibility, cost, and cost responsibility. This delay undermines the ability of generators to compete in the market and provides an unfair advantage to utilities that own both transmission and generation facilities…. Interconnection is a critical component of open access transmission service, and standard interconnection procedures and a standard agreement applicable to Large Generators will serve several important functions: they will (1) limit opportunities for Transmission Providers to favor their own generation, (2) facilitate market entry for generation competitors by reducing interconnection costs and time, and (3) encourage needed investment in generator and transmission infrastructure. The Commission expects that the Final Rule … will resolve most disputes, minimize opportunities for undue discrimination, foster increased development of economic generation, and protect system reliability. *Standardization of Generator Interconnection Agreements and Procedures;* Final Rule, FERC Docket Number EM02-1-000, Order No. 2003; Issued July 24, 2003; at page 3-5.

Finally, what are the potential roles of DG and distributed real-time pricing in a restructured marketplace, and how does the regulatory environment influence their deployment? Electricity producers operate at a number of scales. At the largest scale are the highly centralized producers, usually IOUs with production portfolios that include coal-fired and nuclear power plants. At the middle scale are the less-centralized IPPs, which often operate gas-fired combined-cycle plants. At the smallest scale are the decentralized operators of DG, which produce and consume at the same location, sometimes with excess electricity sold into the public grid.

> [DG] is the name given to small (up to 50 MW) electricity generation facilities, including micro-turbines, fuel cells and small gas turbines, located on the distribution system, close to the point of consumption. [DG] can help reduce the cost and enhance the efficiency of our electrical system. It can lower the demand for the construction of large central station generation facilities, reduce the need for difficult to site transmission facilities, substitute and/or supplement distribution facilities, and reduce overall emissions. *Nat'l Elec. Policy -- Barriers to Competitive Generation: Hearing Before the House Comm. on Energy and Commerce*, (July 27, 2001) (statement of Richard Brent, Dir. of Gov't Affairs, Solar Turbines, Inc., on behalf of the Distributed Power Coalition of Am.).

> Distributed technologies are the electrical equivalent of the personal computer. Computing power used to be concentrated in large-scale mainframe computers with access via 'dumb' terminals at the end-user's location. The last two decades have seen a near-complete transition to microcomputers or minicomputers, each able to operate independently but also frequently linked to other computers to create electronic networks of information. Similarly, the generation of electric power has been concentrated in large-scale central-station facilities with the power transmitted, for the most part unidirectionally, to end-users. Increased reliance on [DG] ultimately will result in a complex web of generating sources, with power flowing in multiple directions through the distribution system. Although for the foreseeable future this transition will not be complete, in that [DG] will supplement rather than replace existing central-station generation, some industry analysts believe that new central-station plants on the order of 1,000 MW (typical of large nuclear and coal-fired power plants) will soon be unheard of. *Nat'l Elec. Policy -- Barriers to Competitive Generation: Hearing Before the House Comm. on Energy and Commerce*, (July 27, 2001) (statement of Thomas J. Starrs, Kelso Starrs and Assoc.).

The greatest benefit of DG is that it minimizes the cost of delivering electricity to the consumer, because the DG unit is located at the place of consumption. In fact, with respect to delivery costs, the optimal location of electricity production is the place of consumption, where the network source and sink are in spatial congruence. Notwithstanding the delivery-cost benefits, production cost is the largest component of total electricity cost, and DG production costs remain high compared to those of central power plants. Nascent economic tension exists between economies of scale from central production and minimization of direct and indirect delivery costs from DG *(Little 1999)*.

> [T]here are relatively few disadvantages of [DG]. The principal one is that [DG] remains more expensive than central-station generation. For example, while installed cost of new central-station generating facilities is between $500 and $1,000 per kW, the cost of combustion-based distributed technologies ranges from $600 to $1,500 per kW, and the cost of cleaner non-combustion technologies such as solar cells, wind turbines, and fuel cells range from $900 to $10,000 per kW. It appears likely, however, that with mass production the cost of many distributed technologies will drop significantly, making them more competitive with central-station generation.
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> ….
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> [DG] reduces energy losses in transmission and distribution lines, provides voltage support, reduces reactive power losses, defers substation upgrades, defers the need for new transmission and distribution capacity, increases reliability of electricity supply and reduces the demand for spinning reserve capacity. In fact, several studies have concluded that under many circumstances (particularly where the utility's distribution system is operating near capacity) non-traditional distributed benefits are comparable in scale to traditional energy and capacity benefits. *Nat'l Elec. Policy -- Barriers to Competitive Generation: Hearing Before the House Comm. on Energy and Commerce*, (July 27, 2001) (statement of Thomas J. Starrs, Kelso Starrs and Assoc.).

Sometimes, transmission constraints that impede delivery of electricity from central power plants will justify a DG installation on the consumer side of those constraints. Plus, DG can serve as a backup to grid electricity, thereby offering reliability assurance from blackouts and brownouts *(Little 2000)*.

> [B]enefits of providing enhanced power quality, relative invulnerability to natural and man-made system outages, and ability to offset requirements to upgrade transmission and distribution systems by offering downstream generation. The Commission should realize that the problems of system reliability, to which the August 14, 2003 northeast blackout … called attention, cannot be solved without a major increase in the amount of load-sited generation resources available to our economy's growing power demand. *Standardization of Small Generator Interconnection Agreements and Procedures*; NOPR, FERC Docket Number RM02-12-000; Issued July 24, 2003 (comment of the Combined Heat and Power Ass'n; submitted Oct. 3, 2003; at page 4).

In addition to backup electricity, DG can provide "peak shaving" by producing electricity during times of peak demand when grid electricity is expensive. In real-time, DG becomes a "put option" held by the operator of the DG unit. As price signals indicate that the unit's fuel-to-electricity conversion efficiency is economic, the DG operator will produce its own electricity rather than purchase higher-cost electricity from the public grid *(Faruqui and Maulden 2002)*.

Convergence between DG, distributed controls, and the Internet will eventually allow utilities and third-party energy-services companies to (1) reduce customer consumption at peak-demand periods by shutting down non-critical appliances and systems at the customer's site, and (2) start and monitor the customer's DG unit. If the DG unit is fully interconnected and "net metered," excess production can be sold into the grid. This widely deployed and dispersed method of electricity conservation and production, in response to local price signals, will contribute to the formation of efficient markets by smoothing volatility *(Cummings and Marston 1999, Little 1999, Cowart 2001, Lesser and Feinstein 2002)*.

> One of the more crucial aspects of a successful wholesale power market is enabling customer demand response and small-scale generation.… One of the best ways to stabilize volatile energy prices and check supplier market power is to ensure that customers can respond to market signals by reducing their consumption…. [E]ven a small amount of demand response can have a significant impact in dampening prices during times of high demand and resource scarcity. All customers benefit from demand response. And one way for customers to respond to high electricity prices is to turn on their own small generators, reducing their load on the electric system on the other side of the customer meter. *Standard Elec. Market Design: Hearing Before the Senate Comm. on Energy and Natural Resources,* (Sept. 17, 2002) (statement of Pat Wood, Chairman, FERC).

Notably, the difference between peak and off-peak wholesale electricity prices is dramatic, with very little of this volatility currently absorbed in the retail markets.

> [C]onsumption is supplied by three types of generators: (1) low cost, base load capacity units that produce at a steady hourly rate; (2) intermediate cost, load-following generator capacity units that are able to ramp up their output as consumption increases from the low off-peak hour levels, and down from the peak hours; (3) high cost, peaking capacity generators that are only turned on for the peak consumption hours. The marginal cost of energy supply alone during the peak hours of consumption can easily be six or more times the corresponding cost for off-peak consumption.… Market efficiency, however, requires the capital investment cost of peaking generators and peak transmission capacity to be charged only to the peak end users, whose demand requires such investments. Hence, the on-peak energy and capital costs could easily be estimated to be ten or more times the off-peak costs. *The California Energy Crisis -- Causes, Impacts, and Remedies: Hearing Before the House Committee on Financial Services,* (June 20, 2001) (statement of Prof. Vernon L. Smith, Dir. Econ. Science Laboratory, Univ. of AZ).

Like retail electricity prices themselves, DG and demand-response programs tied to retail-price fluctuations fall under state jurisdiction. Nonetheless, some proponents of these programs advocate a role for the FERC.

> Demand response programs enable customers to manage their load requirements, encourage reliability and conservation of resources, and offer market opportunities for alternative resources.… FERC rules must mandate that uniform, demand response initiatives be developed at the regional level and closely integrated with the real-time market.… Members are aware of the jurisdictional arguments against the implementation of demand response programs at the regional level that assert that demand response programs are, in effect, retail services rather than wholesale services. However, the jurisdictional issues should not bar the implementation of demand response programs that are essential to a robust competitive market…. *Remedying Undue Discrimination through Open Access Transmission Service and Standard Elec. Market Design*, NOPR, FERC Docket Number RM01-12-000; Issued July 31, 2002 (comment of the Mid-Atlantic Conference of Regulatory Utilities Comm'rs, submitted Nov. 15, 2002).

> Demand response lies squarely at the nexus between wholesale and retail energy markets and jurisdiction -- demand response to price is critically needed in wholesale markets, but it will only occur if retail customers see a price (or price proxy) and change their load accordingly…. [S]tate regulators have the ability and authority to enable retail customers to see the wholesale energy price (or not) and to give them options to respond to it (or not). *Standard Elec. Market Design: Hearing Before the Senate Comm. on Energy and Natural Resources*, (Sept. 17, 2002) (statement of Pat Wood, Chairman, FERC).

For DG and real-time demand-response programs to be viable, price signals must be available in the retail markets. But variable or "floating" retail prices are not a part of state restructuring programs, and real-time price signals are unavailable to consumers.

> What must change is the cultural mindset … inherited from state regulation. This mind set is that all retail demand must be served without regard to the differences in individual consumers' willingness to pay for energy. This mind set will change with full-cost time-of-day pricing, which will have the effect of incentivizing customers to prioritize their use of energy, making demand voluntarily responsive to prices.… The effect of these changes will be to create a far more efficient and smoothly functioning market that will not require government intervention. *The California Energy Crisis -- Causes, Impacts, and Remedies: Hearing Before the House Committee on Financial Services*, (June 20, 2001) (statement of Prof. Vernon L. Smith, Dir. Econ. Science Laboratory, Univ. of AZ).

Before states can introduce variable retail pricing on a broad scale, distributed wholesale price signals are necessary. To this end, the FERC has included in its SMD proposal a wholesale pricing concept called "locational marginal pricing" (LMP), which establishes energy and congestion prices at network "nodes" based on optimal generating-unit dispatch and marginal production cost. Under the LMP demand-response program proposed by the FERC, a wholesale buyer will indicate in advance the quantity of electricity it is willing to buy at a specific node at alternative prices. By doing so, the wholesaler will gain certainty about its forward purchase obligations at that node. The wholesaler can then enter into demand-response contracts with its commercial and industrial retail customers supplied from that node. Each contract will specify at what price the customer agrees to reduce its grid consumption. When this price is reached, the wholesaler will contact the customer and request a consumption reduction according to the contractual terms. In an example of peak shaving, the customer might then start an on-site and interconnected DG unit to satisfy its additional electricity needs.

> [L]ack of price-responsive demand is a major structural defect in the electricity market. When a customer is unable to respond to higher prices, there is no way to discipline price increases from suppliers. However, under the … LMP approach, each buyer's bid will indicate the desired amount of power to be bought, the delivery point, and the time period. In addition, each buyer will be allowed to specify bid prices that indicate the quantities it is willing to purchase at alternative prices. Buyers will also be allowed to submit multi-part bids that indicate the time and price constraints under which they are willing to purchase energy. The Commission's LMP approach facilitates demand response programs by allowing an electricity buyer to indicate in advance the price at which it is willing to voluntarily reduce its consumption of electricity. *Standard Elec. Market Design: Hearing Before the Senate Comm. on Energy and Natural Resources,* (Sept. 17, 2002) (statement of Terry Havrill, Comm'r IL Commerce Comm'n).

Despite the benefits of DG, transaction costs associated with grid interconnection are often economically prohibitive. These transaction costs include exit fees, utility "paralleling" fees, and extensive technical requirements. Typically, DG interconnection policies are developed by the local utility and enforced by the state PUC.

> Regulatory barriers include rate and tariff issues, including the imposition by utility regulators of backup or standby charges on distributed generation facilities; distribution wheeling charges for the delivery of power to wholesale or retail customers other than the utility itself; exit fees to discourage efforts to reduce dependence on utility power through self-generation or even demand-side management; and administratively determined buyback rates that do not reflect the economic benefits of distributed generation or clean power generation. *Nat'l Elec. Policy -- Barriers to Competitive Generation: Hearing Before the House Comm. on Energy and Commerce*, (July 27, 2001) (statement of Thomas J. Starrs, Kelso Starrs and Assoc.).

In some instances, by enforcing onerous utility interconnection requirements, state PUCs may be helping vertically integrated IOUs protect their legacy production assets.

> [I]nterconnection obstacles that are so difficult to overcome in cost and time are not related to true safety or technical issues, but are instead related to the utility's desire (shared to some extent by local regulators) not to have the competitive impacts of small generators who serve on-site load and reduce demand for utility generation and throughput on transmission and distribution lines…. *Standardization of Small Generator Interconnection Agreements and Procedures*; NOPR, FERC Docket Number RM02-12-000; Issued July 24, 2003 (comment of the Combined Heat and Power Ass'n; submitted Oct. 3, 2003; at page 3).

Notwithstanding, some state PUCs, including the California PUC, have actively encouraged DG development. In the case of California, this posture is a direct result of the 2000 and 2001 electricity crisis.

> California is a national leader in taking the initiative to support the development of DG. California promotes the installation of DG to help increase the supply, the delivery, and the reliability of electricity in California…. According to the California Energy Commission (“CEC”), there are approximately 2000 MW of DG installed in California. 350 of these MW have been installed since 2001 when California’s DG interconnection rules … were adopted. For purposes of comparison, the total installed generating capacity in California is 55,800 MW, not including DG. Thus, DG currently amounts to nearly 3.5% of total generating capacity in the state.
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> ….
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> Two events, the development of a competitive electricity market and the subsequent energy crisis, have spurred policymakers to adopt initiatives to encourage DG deployment. *Standardization of Small Generator Interconnection Agreements and Procedures*; NOPR, FERC Docket Number RM02-12-000; Issued July 24, 2003 (comment of the CA Pub. Utilities Comm’n; submitted Oct. 3, 2003; at pages 2-3).

Presently, with regard to DG interconnection, most of the onus is on utilities to oppose or embrace DG because they manage the electrical grid. Critical interconnection issues are (1) technology requirements, (2) DG application size, (3) demand charges, and (4) net metering. Net metering, which allows the DG operator to sell electricity into the grid, creates technical issues of its own including synchronization, power-flow tracking, and maintaining frequency harmonization. The burden for resolving most of these issues rests with the utilities *(Allen 2002, 512-14)*.

Utilities have been reluctant to establish technical standards for interconnection, and the utility industry as a whole has little incentive to create uniform interconnection standards. As a result, a DG developer planning multiple sites requiring interconnection to multiple utilities may face an entirely different set of standards for each utility.

> [D]evelopment of [DG] is thwarted, in part, because potential developers do not have the resources to navigate the crazy quilt of varying standards found across jurisdictions and across utilities. Uniform interconnection standards would go a long way toward helping [DG] reach its potential.… [DG] offers the very real prospect of "plug and play" technology. Many [DG] resource technologies have become modular and standardized as well as relatively easy to transport. It would be -- and today is -- an enormous waste of resources for prospective [DG] developers to go from state to state to persuade legislatures, one at a time, of the benefits and appropriate designs of standardized interconnection procedures. *Nat'l Elec. Policy -- Barriers to Competitive Generation: Hearing Before the House Comm. on Energy and Commerce*, (July 27, 2001) (statement of Richard Brent, Dir. of Gov't Affairs, Solar Turbines, Inc., on behalf of the Distributed Power Coalition of Am.).

> The dominant technical barrier for most [DG] technologies is the failure to adopt uniform standards for interconnection to the utility grid.... Business practice barriers consist of contractual and procedural requirements for interconnection of [DG] facilities. Among the most common complaints of owners and developers of [DG] facilities is the absence of simple, standardized procedures among local jurisdictions and utilities for processing permitting and interconnection requests. *Nat'l Elec. Policy -- Barriers to Competitive Generation: Hearing Before the House Comm. on Energy and Commerce*, (July 27, 2001) (statement of Thomas J. Starrs, Kelso Starrs and Assoc.).

Utility resistance to DG, which manifests as opposition to interconnection, may relate to transition losses. An immediate cost to utilities arises with interconnection studies, a series of utility determinations of what effect the connection of a specific generator might have on the grid. Plus, costs arise in planning to accommodate the type of standby service the DG operator will require, and determining how it will affect the utility's distribution system. One point of contention between DG proponents and utilities concerns what share of these costs DG operators will be assessed *(Allen 2002, 512-13)*.

> The technical aspects of interconnection are critically important. No less important are the standardized procedural and cost allocation rules that all parties involved should be required to follow when determining what resources will be required to interconnect [DG] to the distribution network, and how the costs of those facilities should be shared between the [DG] developer and the utility. *Nat'l Elec. Policy -- Barriers to Competitive Generation: Hearing Before the House Comm. on Energy and Commerce*, (July 27, 2001) (statement of Richard Brent, Dir. of Gov't Affairs, Solar Turbines, Inc., on behalf of the Distributed Power Coalition of Am.).

In August 2002, the FERC issued an Advanced Notice of Proposed Rulemaking (ANOPR) on "Standardization of Small Generator Interconnection Agreements and Procedures," and followed with an NOPR in July 2003. The FERC collaborated with the National Association of Regulatory Utility Commissioners (NARUC) and the Institute of Electrical and Electronics Engineers (IEEE) in developing the proposed rule. The NOPR divides small generators into two categories: two MW and smaller, and between two and twenty MW. The interconnection agreements and procedures (IA and IP respectively) proposed for the smaller category are similar to those used in Texas. The proposed IAs and IPs for the larger category are based on those of the PJM Interconnection. Both sets of standards seek "a reasonable balancing of burdens" *(Allen 2002, 515-16)*.

Underlying these interconnection issues is the question of who will bear the cost of transition to the type of open-market system DG might create. "Many of the barriers facing [DG] are state-level barriers, such as discriminatory rate structures for standby power and exit fees designed to recover so-called 'stranded costs.'" *Nat'l Elec. Policy -- Barriers to Competitive Generation: Hearing Before the House Comm. on Energy and*

Commerce, (July 27, 2001) (statement of Richard Brent, Dir. of Gov't Affairs, Solar Turbines, Inc., on behalf of the Distributed Power Coalition of Am.).

Most state restructuring programs allow utilities full recovery of stranded costs. Operators of DG units within the two-to-twenty MW category that either sell excess off-peak electricity to the grid or buy supplemental peak electricity from the grid create the greatest stranded-cost potential. These DG operators may not pay their fair share of stranded costs, which are usually recovered in retail rates, because they will purchase a smaller percentage of their electricity from the grid. In contrast, DG units under two MW have a low stranded-cost potential, and utilities can more easily integrate the benefits of these small DG units into their legacy distribution systems. Smaller DG applications will be more evenly dispersed around the grid, allowing utilities to avoid T&D upgrades; and are more likely to be peak-shaving units, which help the utilities manage demand spikes. Under the NOPR, generators below two MW will incur less of the overall financial burden of DG implementation than generators in the larger category, perhaps encouraging a preference for smaller DG applications *(Allen 2002, 513-16).*

As with other FERC initiatives, including the SMD, the NOPR for small generator interconnection has prompted jurisdictional disputes, as well as claims that the NOPR does not do enough, or does too much. In general, jurisdictional complaints arise from state PUCs, while complaints that the proposed rule does not do enough come from DG developers. Complaints that the proposed rule does too much originate from (a) utilities with interests to protect, and (b) RTOs with DG interconnection rules already in place. Representative discourse is presented below.

The FERC lacks jurisdiction

> [T]he expansion of FERC jurisdiction that the small generators seek would not only violate the [FPA], but also would undermine Congressional intent in the adoption of that law to preserve the traditional police power of the states to the greatest extent constitutionally permissible…. The FPA was enacted to fill in gaps not covered by state regulation, not as a mechanism for avoiding state regulation of public utilities. In enacting the FPA, Congress did not purport to exercise all of the authority it might have exercised under the Commerce Clause, because its intention was to preserve, not override, state regulatory jurisdiction….
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> ….
>
> California and the other states must manage their power systems in view of their own unique conditions and circumstances, and would be ill served if this local control were pre-empted by a nationally standardized system managed from Washington, DC. Moreover, the experience to date in California and other states, including New York, Ohio and Texas, proves beyond a doubt that the States can manage, and successfully have managed, their power systems to accommodate DG in light of their own individual circumstances, such that FERC's Proposal in its current form is neither justified nor proper. FERC can play an important role in assisting other states that have not yet developed their own DG interconnection rules to follow the lead of states like California. In doing so, however, FERC should not, and must not, preempt the local jurisdiction and control over DG interconnection that California and other states have exercised and successfully implemented….
>
> ….
>
> It is clear from positive experiences that small generators have had in states like California, which have already taken many steps to encourage the development of DG, that (1) existing State interconnection rules fully meet the needs of the small generators seeking to connect to State-jurisdictional utility distribution systems; (2) such State-adopted procedures provide small generators the "one-stop shop" that they presumably seek to achieve through the Proposal; and (3) the small generators have no actual or legitimate need for FERC assistance to cover interconnections to State-jurisdictional facilities in States where DG interconnection rules are already in place. Interestingly, the four large States that have already adopted their own DG interconnection rules account for nearly one-third of the population of the entire country. We question whether the bootstrap expansion of FERC's jurisdiction through "national standardization" is either necessary or justified under circumstances in which states representing such a large percentage of the national population, acting within their own jurisdictional authority and without any prompting from FERC, have already implemented the policy that FERC seeks to broaden to the whole country through this NOPR….

> If FERC is concerned that some states are “behind the curve” in facilitating the interconnection of small merchant generation to existing utility distribution systems that are state-jurisdictional, FERC can certainly encourage such states to follow the lead of California, Ohio and the others. FERC may even establish non-binding guidelines, or a model rule, for use by those states that have not adopted their own standards….
>
> ….
>
> [T]he adoption by FERC of the Proposal set forth in the NOPR would be bad public policy, in that it would impose a rigid model…. As the existence of the California interconnection procedures amply demonstrates, major states are already facilitating and encouraging generator interconnection. There is accordingly no public policy justification for a rigidly uniform federal interconnection standard for DG…. One size does not fit all…. FERC must recognize that a “federal solution” is not necessarily the best way….
>
> ….
>
> [T]he key principle that FERC ought to recognize and accept is that any rule that FERC ultimately adopts relating to small generator interconnections should be a Model for adoption by the States, not a mandate into which all States must be squeezed irrespective of the differences between them and their respective regulatory programs. FERC should see this rulemaking as an opportunity to engage in “cooperative federalism” with the states.… *Standardization of Small Generator Interconnection Agreements and Procedures*; NOPR, FERC Docket Number RM02-12-000; Issued July 24, 2003 (comment of the CA Pub. Utilities Comm’n; submitted Oct. 3, 2003; at pages 8-23).

The NOPR does not do enough

> Unless the Commission is willing to modify the proposed rule in fundamental ways … small resource development would be better served if the rule were simply withdrawn…. The NOPR order … fundamentally misstates the situation faced by the industry vis-à-vis small distributed resources.... [F]raming interconnection issues as a competition between maintaining system reliability and encouraging small resources is wholly inappropriate, and it gives disproportionate weight to the reliability “concerns” of transmission/distribution owners with generating units of their own…. The underlying issue before the Commission here is not whether interconnection of small resources harms reliability. Indeed, small resources will significantly improve reliability because the true threats to reliability, as recent weeks have proven, come from grid constraints, large power plant outages, and high voltage facilities.…

> Rather, the underlying issue in this docket is whether the public utilities that currently dominate generation, as well as transmission and distribution on the grid, can avoid the oncoming competition of a host of small generating technologies that threaten to substitute for both their generation and their wires…. [O]ur nation's electric system can only regain reasonable reliability, system security, and power quality with a proliferation of small resources on the grid -- not by reinforcing the operational and institutional monopolies that typically have blocked technical and market innovations. *Standardization of Small Generator Interconnection Agreements and Procedures*; NOPR, FERC Docket Number RM02-12-000; Issued July 24, 2003 (comment of the Small Generator Coalition; submitted Oct. 3, 2003; at pages 7-9).

<u>*The NOPR does too much*</u>

> [T]he NOPR's proposed pricing policy for transmission upgrades caused by interconnecting small generators would inappropriately shift those interconnection costs to customers who often realize no commensurate benefits. These cost socialization policies … violate [EPAct], violate basic principles of cost causation, and fail to provide appropriate price signals for generators.… The NOPR also proposes to impose a discriminatory policy of only allowing transmission providers (and their customers) that are part of an RTO or ISO to escape these flawed cost socialization policies by allowing such entities to adopt alternative pricing methodologies. Not only is this approach inappropriate for being discriminatory, but it also amounts to a prohibited indirect attempt by the Commission to mandate RTO formation. *Standardization of Small Generator Interconnection Agreements and Procedures*; NOPR, FERC Docket Number RM02-12-000; Issued July 24, 2003 (comment of Southern Company Services; submitted Oct. 3, 2003; at page 2).

> PJM's experience shows that its current procedures serve the same objectives as the NOPR, in that they: (1) reduce interconnection time and study costs for small generation projects; (2) minimize opportunities for discrimination; (3) ease barriers to entry for small generators; and (4) encourage needed investment in generation and transmission infrastructure….
>
> ….

> PJM urges the Commission to afford greatest flexibility to transmission providers that already have fully-developed and well-functioning procedures to expedite small generation resource interconnections. The PJM Tariff … includes detailed procedures, developed through an extensive stakeholder process, for the study and other processing of requests for interconnection of new generation….
>
> ….
>
> PJM also encourages the Commission to permit RTOs and ISOs to maintain existing small generation interconnection processes that have proven track records and manageable deadlines with which developers … and transmission providers can and have complied. *Standardization of Small Generator Interconnection Agreements and Procedures*; NOPR, FERC Docket Number RM02-12-000; Issued July 24, 2003 (comment of PJM Interconnection; submitted Oct. 3, 2003; at pages 4-6).

Chapter Six: Conclusions

Summary of Findings

The central question of this study is the following: how do overlaid state and federal jurisdictions, combined with the unique technological and regulatory characteristics of the U.S. electricity industry, impact restructuring? In constructing a coherent set of arguments to answer this question, the study reveals an ongoing struggle between incumbents and the "state" that complicates the industry's evolutionary path. Plus, the wholesale trade analysis shows gaps between state and federal regulation, adding another level of complexity to restructuring in this industry.

The wholesale trade analysis examines differences in trade patterns between stand-alone IOUs and those affiliated with MHCs. These patterns indicate transfer pricing and trade diversion among IOU affiliates of MHCs, which act as entry barriers and impede regional market formation. These intra-firm transactions are not well monitored by either state or federal regulatory agencies. Regulatory failures associated with the California, Enron, and Blackout events further highlight the complex relationships between the industry and various institutions.

The U.S. electricity industry is evolving from a rigid and highly regulated structure, descriptive of the industry from the 1930s through the 1970s, to a more-flexible and less-regulated structure. Two interrelated processes are at work. First is the political-economic process, which shapes the regulatory environment within which restructuring occurs. Second is the actual industrial-restructuring process, which follows an emerging pattern of flexible capital accumulation.

The political-economic process is mediated through the federalist system, subject to centripetal and centrifugal forces. Centripetal political-economic forces encourage central regulatory oversight and standard rules, while centrifugal political-economic forces encourage decentralized oversight and regionally flexible rules. Within the industry's dual regulatory framework, federal regulation is a centripetal force while state regulation is a centrifugal force.

The industrial-restructuring process is mediated through institutions reflecting the activities of producers, consumers, legislators, regulators, and other stakeholders. Like the political-economic process, the industrial-restructuring process is subject to centripetal and centrifugal forces. Centripetal forces support the legacy structure or status quo, namely vertically integrated utilities with central production and franchise service territories. Centrifugal forces encourage vertical de-integration and external economies including physical and financial trade, decentralized production, distributed real-time pricing, and real-time demand response.

The restructuring process is contentious and volatile, and the state is a participant in the struggle. Under the U.S. federalist system, the "state" includes both state and federal institutions, which have overlapping jurisdictional authority. A successful restructuring of the U.S. electricity industry requires a relational contract among state institutions, federal institutions, and industry participants. Also needed is a governance system that encourages cooperative discourse.

The imperfect nature of regulation, shaped by the input of numerous stakeholders and characterized by "irrational equilibrium," highlights the importance of context in understanding regulatory processes. Context is provided by discursive practices operating through institutions. Ultimately, discursive practices drive restructuring, and the formal legal processes that frame these discursive practices fall within the rubric of administrative law or “real” regulation.

The study’s wholesale trade analysis demonstrates the existence of state-federal regulatory gaps. These gaps allow advantages for incumbent vertically integrated utilities, which likely want to maintain the status quo rather than lose those advantages. Incumbents will use the political process -- especially their influence over state legislatures and regulatory agencies -- to impede federal deregulation, often relying on jurisdictional arguments. A conflict between a federal agency and incumbent utility is thereby elevated to a jurisdictional dispute. If nothing else, by delaying deregulation an incumbent can enjoy its advantages longer, and perhaps gain additional political capital.

Incumbent utilities without special advantages may still resist deregulation because of regulatory transition losses. Legacy regulation and the inherited configuration of costs and prices influence the characteristics and size of these losses, and managing them invokes both regulatory and market responses. First, incumbents may use regulatory processes to delay deregulation or transfer transition losses to others. Second, they may use market processes, in coordination with regulatory agencies, to make intrinsic structural changes.

With deregulation, regulatory agencies promote markets by lowering entry barriers and reducing commercial and regulatory transaction costs. As commercial transaction costs decline under deregulation, electricity markets will grow larger and resource allocation will become more efficient. But some incumbent utilities may want to preserve commercial transaction costs imposed by the legacy structure. For example, transaction costs in the form of transmission constraints can act as entry barriers that reduce geographic market size, thereby creating opportunities for incumbents to exercise market power.

In the early stages of deregulation, the regulatory transaction costs of designing and implementing electricity markets are high. But once markets are functional, regulatory transaction costs decline as agencies assume a less-interventionist role. At that point, private regulation and market discipline protect market integrity. The task for state and federal regulatory agencies is to gradually decrease intervention in areas with competition and market discipline, while remaining active in areas susceptible to abuse.

California market manipulation, the Enron scandal, and the regional blackout all were multi-jurisdictional events beyond the regulatory capabilities of state agencies. By the same token, states cannot embrace federal intervention only in times of crisis. Together, state and federal institutions must develop a regulatory framework that fills the gaps that allowed these crises to occur. These events point to the need for coordinated planning, well-designed rules, strong oversight, and active intervention to manage the market imperfections exposed by deregulation. In particular, they underscore the need for more cooperation among federal regulatory agencies, and between state and federal agencies. First, the FERC must work more closely with the CFTC and SEC on market design and oversight. Second, state jurisdictional authority is not plenary; and federal regulation, because it overlays state regulation, must fill the gaps.

States cannot regulate interstate electricity trade, and because the wholesale and retail markets will become more linked over time, state and federal institutions must work together on a market design for physical trade. Wholesale and retail markets must be coordinated, especially as DG, distributed real-time pricing, and real-time demand response are adopted. In the short term, electricity trade will be primarily physical as opposed to financial. Financial electricity trade is highly complex, and the physical properties of electricity discourage arbitrage discipline. Until liquidity sufficient to impose market discipline has developed, electricity-derivatives markets will require strong oversight by the CFTC and FERC. Going forward, well-capitalized banks will provide the financial liquidity necessary to "make markets" in electricity derivatives, but not until demand increases to align better with supply and wholesale prices begin to experience more volatility.

Capital flows are a market's report card, and the U.S. electricity industry's large capital outflow following the California and Enron debacles reflects a failure to develop functional markets. Market and regulatory failures have dramatically restricted capital and credit availability, slowed the progress of electricity market liberalization, and created significant uncertainty. Capital is not likely to return to the sector until the regulatory environment has stabilized. Capital for transmission expansion is especially needed, but may first depend on resolution of the FERC's SMD proposal so that investors have some measure of certainty.

Although transmission capacity is in short supply, an abundance of new production capacity exists, stemming from a power-plant overbuild during the wholesale price bubble. Contributing to the production overbuild were regulatory initiatives that reduced entry barriers for power-plant development. Plus, most of the new power plants use advanced high-efficiency combined-cycle technologies. These technologies have lowered scale economies for electricity production, and allow for cost-effective and decentralized production using smaller and less-capital-intensive plants. Regulatory and technological factors combined to encourage greater geographic diversification of production by merchant producers, which reduces volatility for both merchant portfolios and the market as a whole. Decentralized production improves market efficiency by more closely balancing supply with demand along the electrical grid.

DG takes decentralized production even further, and provides the closest spatial and temporal match between production and consumption. DG electricity remains substantially more expensive than grid electricity; but becomes more cost effective if other benefits of DG are recognized, including its value as emergency backup or source of supplemental supply. During times of peak electricity demand, when central resources are scarce and prices high, supplemental distributed resources smooth prices and improve reliability. This practice of “peak shaving” places DG at the spatial and economic margins, and combines the benefits of central and decentralized production.

The flexibility benefits of DG and real-time demand response can be realized only when distributed real-time prices are available in the retail markets, and DG is widely interconnected to the electrical grid. The wholesale markets are not yet robust enough to provide distributed real-time price signals to the retail markets, and local barriers to DG interconnection remain. An eventual combination of improved DG production efficiency, easier interconnection, and distributed real-time pricing will support the full benefits of decentralized and flexible production and conservation.

The RTO structure supports lower commercial transaction costs, larger markets, and more efficient resource allocation. It also provides a framework for (a) physical and financial electricity trade, (b) market monitoring and information gathering, (c) the prevention of market gaming, (d) infrastructure development, (e) DG and distributed real-time pricing, and (f) improved reliability. The process of creating RTOs will increase regulatory transaction costs in the short term, but reduce overall transaction costs and improve market efficiency in the long term. Despite the advantages, challenges to RTO formation are numerous and include (1) jurisdictional disputes between state and federal regulatory agencies; (2) disagreement about accountability and the value of primary regulators being "close," both geographically and culturally, to the regulated entities and affected consumers; (3) concerns by low-cost states that their electricity will be exported to other states within RTOs, resulting in higher prices for themselves; and (4) captured state institutions that further the protectionist agendas of incumbents.

Implications

This study attempts to unravel how overlaid state and federal jurisdictions, combined with the unique technological and regulatory characteristics of the U.S. electricity industry, impact restructuring. First, as the national production and delivery systems become more flexible and horizontally integrated across multi-state areas, federal market design and central regulatory oversight become increasingly relevant. Second, decentralized production and distributed real-time pricing are important for reducing market volatility, providing reliable price signals for capital investment, and promoting conservation in times of shortage. In sum, the restructuring process is one of centripetal forces influencing the mode of regulation, while centrifugal forces influence patterns of capital accumulation. The emerging RTO structure, with central governance and a multi-state market, can accommodate this combination of centripetal and centrifugal forces.

In this analysis, a realist process of conceptualization invokes several levels of abstraction. French regulation theory operates at a high level, federalism at an intermediate level, and “real” regulation at a low level. Realism gives way to pragmatism at the low level of abstraction. A methodology of combining realism at high and intermediate levels of abstraction with pragmatism at low levels of abstraction is useful for geographers examining regulation at various scales. In general, borrowing from legal theory as it relates to “real” regulation injects the philosophy of pragmatism at institutional scales, which frees the researcher to embrace the complexities of the regulatory process.

The analysis illuminates the RTO as a “place” where discursive practices, operating through various institutions, are assuming structure as a new institutional space. Place is a process, not an object; and discursive practices will continue to influence, and be influenced by, a maturing RTO structure and its associated governance system. Meanwhile, forces with the potential to delay or halt RTO formation are pushing in the opposite direction, toward the status quo. An RTO requires that states concede some jurisdictional authority for the benefit of the region as a whole, and the support of state institutions is critical. Because legacy regulation and patterns of accumulation impact RTO structure, the FERC must be willing to accept regional variability from a “standard” market design. To be successful, the processes of designing and implementing an RTO must evolve within the boundaries of a relational contract, where policymakers maintain a balance between federalism and regionalism. A strong relational contract among state institutions, federal institutions, and industry participants will produce a governance system that advances RTO formation. Simultaneously, policymakers can initiate processes that promote gradual RTO harmonization and integration, preferably through the work of market forces.

Limitations and Future Direction

The U.S. electricity industry is highly complex, and the context of restructuring is difficult to thoroughly capture. First, the industry has numerous stakeholder groups with varying agendas, resources, and degrees of influence. Outside of an institutional setting, the aggregate impact of these groups is not easily measured. Second, the physics of electricity often trump traditional market mechanisms. For example, physical and network properties often will not allow electricity markets to clear properly, making spot markets volatile and discouraging regional market integration. Third, substantial uncertainty surrounding the restructuring process remains, and not all continuities and contingencies are fully reflected in this study.

One neglected theoretical area is public-choice theory. Because U.S. retail electricity markets are in their infancy, a public-choice analysis was not undertaken. However, as retail markets mature on a state-by-state basis, a study of public-choice mechanisms -- as reflected through the activities of state institutions -- may prove fruitful in evaluating the varying efficacies of state markets. A public-choice analysis may also be useful for measuring the (1) optimal trade-off between reliability and markets for different states and consumer groups, and (2) impact of “green” electricity on consumer choice. First, are some consumers willing to accept lower reliability, including occasional blackouts, in exchange for cheaper electricity provided through market mechanisms? If so, what are the optimal points of intersection between reliability and markets for the residential, commercial, and industrial segments within the various states? What is the proper role for regulatory agencies with regard to reliability requirements? Second, are some consumers willing to pay a premium for electricity produced from renewable resources, including geothermal, hydro, solar, and wind? If so, how do patterns of consumer choice relate to resource allocation and environmental policy as reflected through state institutions?

Other possibilities for empirical research include the following: (1) a state-level study, examining state PUC proceedings, of how the characteristics and size of regulatory transition losses influence patterns of structural change for incumbent utilities, (2) an application of the study methodology to electricity restructuring in the European states, and (3) combined studies of “real” regulation and restructuring for other basic industries, including the steel industry.

Appendix One: Tables and Figures

IOUs included in wholesale trade analysis

Stand-alone IOUs

Arizona Public Service
Atlantic City Electric
Baltimore Gas and Electric
Black Hills Power and Light
Boston Edison
Carolina Power and Light
Central Hudson Gas and Electric
Central Illinois Light
Central Illinois Public Service
Central Louisiana Electric
Cincinnati Gas and Electric
Cleveland Electric
Commonwealth Edison
Consolidated Edison
Consumers Power
Dayton Power and Light
Delmarva Power and Light
Detroit Edison
Duke Power
Duquesne Light
El Paso Electric
Empire District Electric
Florida Power and Light
Florida Power Corp.
Houston Lighting and Power
Idaho Power
Illinois Power
Indianapolis Power and Light
Interstate Power
Kansas City Power and Light
Kansas Gas and Electric
Kentucky Utilities
Long Island Lighting
Louisville Gas and Electric
Minnesota Power and Light
Montana-Dakota Utilities
Montana Power
Nevada Power
Niagara Mohawk Power

Northern Indiana Public Service
Northern States Power
Ohio Edison
Oklahoma Gas and Electric
Orange and Rockland Utilities
Otter Tail Power
Pacific Gas and Electric
Pacificorp
PECO Energy
Pennsylvania Power and Light
Pennsylvania Power
Portland General Electric
Potomac Electric Power
PSI Energy
Public Service Company of New Mexico
Public Service Company of Colorado
Puget Sound Power and Light
Rochester Gas and Electric
San Diego Gas and Electric
Sierra Pacific Power
South Carolina Electric and Gas
Southern California Edison
Southern Indiana Gas and Electric
Southwestern Public Service
St. Joseph Light and Power
Tampa Electric
Texas Utilities Electric
Toledo Edison
Tucson Electric Power
Union Electric
United Illuminating
Utilicorp United
Virginia Electric Power
Washington Water Power
Wisconsin Electric Power
Wisconsin Power and Light
Wisconsin Public Service

Holding-company IOUs

Appalachian Power
Columbus Southern Power
Indiana Michigan Power
Kentucky Power
Ohio Power
Monongahela Power
Potomac Edison
Central Power and Light
Public Service Company of Oklahoma
Southwestern Electric Power
West Texas Utilities
Arkansas Power and Light
Jersey Central Power and Light
Metropolitan Edison
Pennsylvania Electric
Connecticut Light and Power
Public Service Company of New Hampshire
Western Massachusetts Electric
Alabama Power
Georgia Power
Gulf Power
Mississippi Power
Savannah Electric and Power

Data for wholesale trade analysis

Stand-alone IOUs

IOU		gencst	price	marg	mwcap	kwhexp	kwhimp	$export	$import	$balance	adjbal	tt
Arizona P.S.	AZ	.0452	.0846	.0394	3986.90	1789693	1893156	63240463	39278601	23961862	6010.15	1.70
Atlantic City Elec.	NJ	.0632	.1114	.0482	1678.70	208961	1761459	5802405	61692346	-55889941	-33293.6	.79
Baltimore G&E	MD	.0393	.0725	.0332	5948.00	2576547	2367028	57051251	89115456	-32064205	-5390.75	.59
Black Hills P&L	SD	.0480	.0647	.0167	352.56	176850	368598	2006863	20472038	-18465175	-52374.6	.20
Boston Edison	MA	.0623	.1108	.0485	2737.00	1558061	1815878	89262338	89895223	-632885	-231.23	1.16
Carolina P&L	NC	.0433	.0649	.0216	9853.00	3557251	3611540	69523702	149183585	-79659883	-8084.84	.47
Central Hudson G&E	NY	.0470	.0861	.0391	1107.00	84208	929284	2519628	18795951	-16276323	-14703.1	1.48
Central Illinois Light	IL	.0332	.0562	.0230	1152.00	366792	293550	7591079	9127275	-1536196	-1333.50	.67
Central Illinois P.S.	IL	.0344	.0653	.0309	2859.00	2523763	1334655	60065354	24815777	35249577	12329.34	1.28
Central Louisiana Elec.	LA	.0279	.0541	.0262	1693.00	151	10532	4477	252961	-248484	-146.77	1.23
Cincinnati G&E	OH	.0320	.0636	.0316	3588.00	7833780	2763066	220714907	51493822	169221085	47163.07	1.51
Cleveland Elec.	OH	.0594	.0862	.0268	4041.00	755217	1278403	12435645	106311329	-93875684	-23230.8	.20
Commonwealth Edison	IL	.0517	.0830	.0313	18600.00	8384204	5826135	133319237	199104936	-65785699	-3536.87	.47
Consolidated Edison	NY	.0535	.1354	.0819	8291.00	627379	5521324	14049814	121717018	-107667204	-12986.0	1.02
Consumers Power	MI	.0422	.0655	.0233	7200.00	1607152	3769741	40338496	89489848	-49151352	-6826.58	1.06
Dayton P&L	OH	.0452	.0684	.0232	3194.00	577739	625240	12277753	12854195	-576442	-180.48	1.03
Delmarva P&L	DE	.0411	.0704	.0293	2769.00	51180	2415285	1269639	52073579	-50803940	-18347.4	1.15
Detroit Edison	MI	.0489	.0777	.0288	10225.00	1572859	3264600	35793991	65875215	-30081224	-2941.93	1.13
Duke Power	NC	.0381	.0560	.0179	17100.00	1956314	1527719	108933207	33017986	75915221	4439.49	2.58
Duquesne Light	PA	.0470	.0892	.0422	2670.00	3136240	610424	56312850	12390499	43922351	16450.32	.88
El Paso Elec.	TX	.0497	.0813	.0316	1500.00	721851	643537	16043530	18508826	-2465296	-1643.53	.77
Empire District Elec.	MO	.0273	.0515	.0242	878.00	184384	919803	3686654	20801071	-17114417	-19492.5	.88
Florida P&L	FL	.0455	.0698	.0243	16416.00	407985	1199112	15601035	22091871	-6490836	-395.40	2.08
Florida Power	FL	.0450	.0703	.0253	7717.00	191414	815579	10037349	30408653	-20371304	-2639.80	1.41
Houston L&P	TX	.0442	.0580	.0138	14040.00	321394	201943	21995047	7741328	14253719	1015.22	1.79
Idaho Power	ID	.0209	.0386	.0177	364.50	3239956	1027143	51178600	21143451	30035149	82400.96	.77
Illinois Power	IL	.0473	.0704	.0231	4000.00	2933873	2016411	62957515	33472125	29485390	7371.35	1.29
Indianapolis P&L	IN	.0301	.0503	.0202	2956.00	108116	193104	1785676	17917747	-16132071	-5457.40	.18
Interstate Power	IA	.0310	.0504	.0194	1028.10	229977	1169350	3103944	28655232	-25551288	-24852.9	.55

Kansas City P&L	MO	.0360	.0674	.0314	3297.00	2146068	734345	35791876	14148365	21643511	6564.61	.87
Kansas G&E	KS	.0392	.0722	.0330	5319.00	915804	332122	21319239	7543226	13776013	2589.96	1.02
Kentucky Utilities	KY	.0259	.0417	.0158	3718.00	830986	1638768	17314099	33161161	-15847062	-4262.25	1.03
Long Island Lighting	NY	.0515	.1537	.1022	4325.00	52847	1119974	2102934	24191029	-22088095	-5107.07	1.84
Louisville G&E	KY	.0313	.0503	.0190	2592.00	505040	383041	12148272	6125582	6022690	2323.57	1.50
Minnesota P&L	MN	.0241	.0398	.0157	1144.00	2422186	144058	53390906	2026741	51364165	44898.75	1.57
Montana-Dakota	ND	.0305	.0624	.0319	393.00	266855	290593	4361701	7805309	-3443608	-8762.36	.61
Montana Power	MT	.0238	.0487	.0249	1157.40	1893912	662288	48910501	10830103	38080398	32901.67	1.58
Nevada Power	NV	.0386	.0626	.0240	1964.00	67658	2427819	1343595	59038411	-57694816	-29376.2	.82
Niagara Mohawk	NY	.0528	.0934	.0406	3788.00	709468	136868	17934127	2806864	15127263	3993.47	1.23
Northern Indiana P.S.	IN	.0374	.0630	.0256	3392.00	627825	840598	10524928	15422572	-4897644	-1443.88	.91
Northern States Power	MN	.0309	.0573	.0264	7117.00	8459588	1548809	224795495	72487467	152308028	21400.59	.57
Ohio Edison	OH	.0485	.0851	.0366	4933.00	4424140	2656821	165604726	53330949	112273777	22759.74	1.86
Oklahoma G&E	OK	.0308	.0546	.0238	5647.00	288128	232015	6177982	4320029	1857953	329.02	1.15
Orange & Rockland	NY	.0431	.1050	.0619	981.00	1493477	1413611	71469282	35151723	36317559	37020.96	1.92
Otter Tail Power	MN	.0239	.0551	.0312	650.61	311469	68321	5050739	1282905	3767834	5791.23	.86
Pacific G&E	CA	.0583	.1047	.0464	10938.10	255598	838361	4025321	16000322	-11975001	-1094.80	.83
Pacificorp	OR	.0249	.0475	.0226	8282.00	12006353	5091198	344981357	91488217	253493140	30607.72	1.60
PECO Energy	PA	.0553	.0993	.0440	9203.80	14712025	12648670	364814829	223413896	141400933	15363.32	1.40
Pennsylvania P&L	PA	.0471	.0721	.0250	8257.00	9428431	2219677	347163162	64270524	282892638	34260.95	1.27
Pennsylvania Power	PA	.0451	.0707	.0256	824.00	653781	1040663	24545016	15851354	8693662	10550.56	2.46
Portland General Elec.	OR	.0220	.0514	.0294	2120.00	3372147	2479911	60855557	59015092	1840465	868.14	.76
Potomac Elec.	MD	.0378	.0724	.0346	6126.00	3933883	8963342	92882849	296054391	-203171542	-33165.4	.71
PSI Energy	IN	.0267	.0456	.0189	5820.00	4787426	6941485	95125782	124764773	-29638991	-5092.61	1.11
P.S. of New Mexico	NM	.0501	.0805	.0304	1506.00	3095674	839636	79928634	29126348	50802286	33733.26	.74
P.S. of Colorado	CO	.0355	.0616	.0261	3760.00	1226785	1790785	34908185	57415933	-22507748	-5986.10	.89
Puget Sound P&L	WA	.0250	.0585	.0335	1754.00	2439569	2571156	33272104	98030904	-64758800	-36920.6	.36
Rochester G&E	NY	.0488	.1027	.0539	1239.00	279500	387770	5645227	7475924	-1830697	-1477.56	1.05
San Diego G&E	CA	.0497	.0977	.0480	2403.00	184514	2602610	2940572	97006716	-94066144	-39145.3	.43
Sierra Pacific Power	NV	.0381	.0694	.0313	1092.20	91368	2509712	1816623	65541214	-63724591	-58345.2	.76
South Carolina E&G	SC	.0341	.0576	.0235	4350.00	196119	4314799	5101504	101573689	-96472185	-22177.5	1.10
Southern CA Edison	CA	.0663	.1060	.0397	21511.00	551587	3008290	30151775	88805531	-58653756	-2726.69	1.85
Southern Indiana G&E	IN	.0337	.0499	.0162	1236.00	312721	238030	6848273	3920966	2927307	2368.37	1.33
Southwestern P.S.	TX	.0267	.0444	.0177	4555.00	881231	563804	45059025	8798568	36260457	7960.58	3.28
St. Joseph L&P	MO	.0301	.0541	.0240	378.00	58432	148151	1063000	2930521	-1867521	-4940.53	.92

Tampa Elec.	FL	.0404	.0704	.0300	3600.00	1325205	79632	32114925	3383147	28731778	7981.05	.57
Texas Utilities Elec.	TX	.0471	.0640	.0169	21225.00	2284263	109553	115513983	3181014	112332969	5292.48	1.74
Toledo Edison	OH	.0589	.0838	.0249	1832.00	1602535	942528	112202196	13987055	98215141	53610.88	4.72
Tucson Elec. Power	AZ	.0424	.0825	.0401	1952.00	1372035	335835	22250836	4957081	17293755	8859.51	1.10
Union Electric	MO	.0343	.0620	.0277	8541.00	2727860	7906023	73500260	149017017	-75516757	-8841.68	1.43
United Illuminating	CT	.0632	.1197	.0565	1522.00	722555	348147	28621486	21579170	7042316	4627.01	.64
Utilicorp United	MO	.0308	.0650	.0342	1679.00	312873	2773707	7328650	76692128	-69363478	-41312.4	.85
Virginia Elec. Power	VA	.0451	.0654	.0203	13635.00	4243434	5833745	94129696	158267332	-64137636	-4703.90	.82
Washington Water	WA	.0219	.0477	.0258	1688.00	3286354	1744140	92899775	24210901	68688874	40692.46	2.04
Wisconsin Elec. Power	WI	.0314	.0540	.0226	5652.00	897556	1062321	23176207	19765696	3410511	603.42	1.39
Wisconsin P&L	WI	.0284	.0519	.0235	2164.67	1833248	1015448	34915073	23035021	11880052	5488.16	.84
Wisconsin P.S.	WI	.0289	.0484	.0195	1820.00	608451	1591574	14909350	29109140	-14199790	-7802.08	1.34

Variables

gencst -- average native production cost per kWh
price -- average retail price per kWh
marg -- average gross margin per kWh (price - gencst)
mwcap -- native production capacity
kwhexp -- kWh exports
kwhimp -- kWh imports
$export -- dollar amount of exports
$import -- dollar amount of imports
$balance -- trade balance ($export-$import)
adjbal -- size-adjusted trade balance ($balance/mwcap)
tt -- inverse terms of trade [($export/kwhexp)/ ($import/kwhimp)]

Holding-company IOUs

IOU		holdco	gencst	price	marg	mwcap	kwhexp	kwhimp	$export	$import	$balance	adjbal	tt
Appalachian Pow.	VA	AEP	.0253	.0480	.0227	5858.00	4984709	823283	145346053	17673227	127672826	21794.61	1.36
Columbus South.	OH	AEP	.0329	.0658	.0329	2595.00	1245426	338979	33092963	7564734	25528229	9837.47	1.19
Indiana Michigan	IN	AEP	.0326	.0565	.0239	4434.00	3263655	4152447	91992297	103078761	-11086464	-2500.33	1.14
Kentucky Power	KY	AEP	.0204	.0417	.0213	1060.00	519011	2609497	13850755	69921845	-56071090	-52897.3	1.00
Ohio Power	OH	AEP	.0265	.0423	.0158	8512.00	4589479	1304978	128573042	31286767	97286275	11429.31	1.17
Monongahela Pow.	WV	Allegh	.0313	.0553	.0240	2326.00	2532666	1377417	108059092	66828097	41230995	17726.14	.88
Potomac Edison	MD	Allegh	.0313	.0551	.0238	2073.00	1196617	4506918	58731362	187238402	-128507040	-61990.9	1.18
Central P&L	TX	CSW	.0395	.0597	.0202	4377.00	323895	89466	9486043	1996692	7489351	1711.07	1.31
P.S. of OK	OK	CSW	.0263	.0474	.0211	3660.00	43783	39321	1632830	1371362	261468	71.44	1.07
Southwestern	LA	CSW	.0267	.0489	.0222	4474.00	453922	34340	11451347	987344	10464003	2338.85	.88
West Texas	TX	CSW	.0286	.0594	.0308	1228.00	145463	31749	5598979	2103472	3495507	2846.50	.58
Arkansas P&L	AR	Enter	.0340	.0744	.0404	4373.00	2282763	3640653	60144630	250254298	-190109668	-43473.5	.38
Jersey Central	NJ	GPU	.0576	.1128	.0552	2729.00	5382	4667637	369508	193568103	-193198595	-70794.6	1.66
Metropolitan Ed.	PA	GPU	.0461	.0733	.0272	1738.00	4689	654883	261058	26383899	-26122841	-15030.4	1.38
Pennsylvania Elec.	PA	GPU	.0361	.0699	.0338	2284.00	101071	141649	5100639	8671214	-3570575	-1563.30	.82
Connecticut L&P	CT	NEU	.0593	.1039	.0446	5419.40	1122593	6808970	52460371	225516103	-173055732	-31932.6	1.41
P.S. of NH	NH	NEU	.0494	.1230	.0736	1276.20	987084	6123054	40557131	241309225	-200752094	-157305	1.04
Western MA Elec.	MA	NEU	.0503	.1040	.0537	932.60	199727	1689393	6765377	59772509	-53007132	-56838.0	.96
Alabama Power	AL	South	.0340	.0559	.0219	11151.11	5040888	3166368	219804540	86838975	132965565	11923.98	1.59
Georgia Power	GA	South	.0375	.0631	.0256	14946.82	1705354	3431658	59030144	103815124	-44784980	-2996.29	1.14
Gulf Power	FL	South	.0375	.0608	.0233	2173.90	1214780	96478	52258509	2809356	49449153	22746.75	1.48
Mississippi Power	MS	South	.0291	.0504	.0213	2085.55	180553	66145	3291403	2009327	1282076	614.74	.60
Savannah E&P	GA	South	.0350	.0622	.0272	787.63	63724	23345	1201507	707334	494173	627.42	.62

Abbreviations

Holdco -- holding company
Allegh -- Allegheny Power System
AEP -- American Electric Power
CSW -- Central and South West

Enter -- Entergy
GPU -- General Public Utilities
NEU -- Northeast Utilities
South -- Southern Company

Correlation results for wholesale trade analysis

Stand-alone IOUs

		gencst	*marg*	*adjbal*	*tt*
Pearson Correlation	*gencst*	1.000	0.498**	-0.141	0.080
	marg	0.498**	1.000	-0.087	-0.029
	adjbal	-0.141	-0.087	1.000	0.455**
	tt	0.080	-0.029	0.455**	1.000
Sig. (2-tailed)	*gencst*	-	0.000	0.224	0.490
	marg	0.000	-	0.455	0.801
	adjbal	0.224	0.455	-	0.000
	tt	0.490	0.801	0.000	-

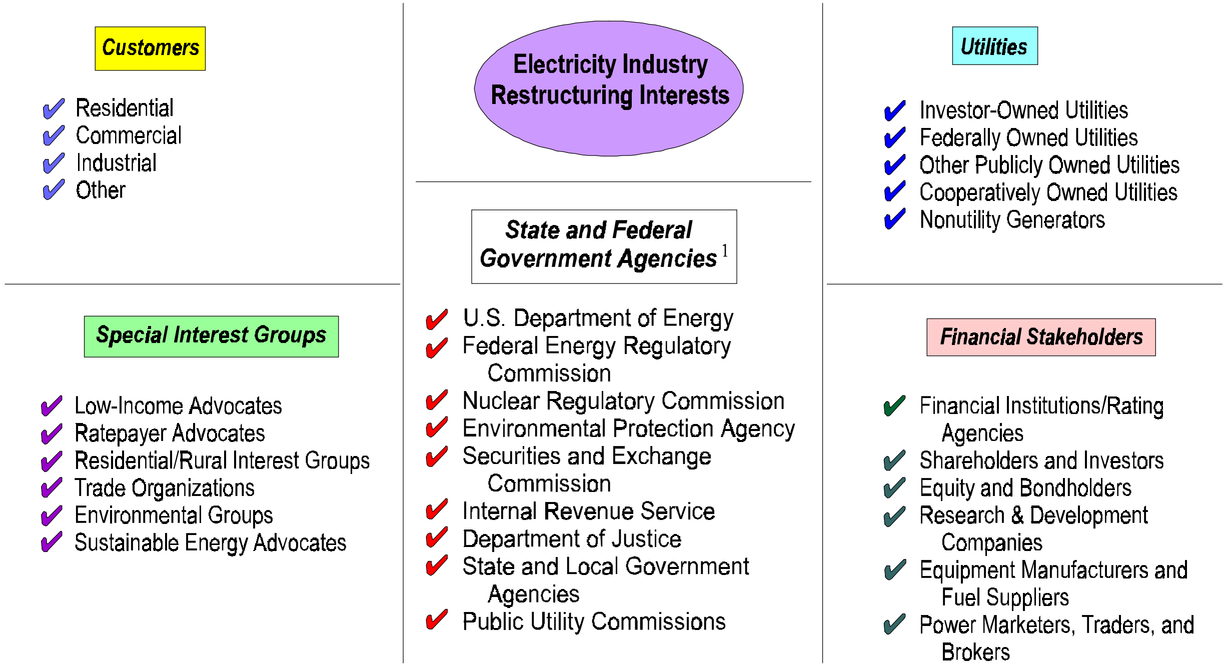
** Correlation is significant at the 0.01 level (two tailed).

Holding-company IOUs

		gencst	*marg*	*adjbal*	*tt*
Pearson Correlation	*gencst*	1.000	0.744**	-0.496*	0.393
	marg	0.744**	1.000	-0.814**	0.011
	adjbal	-0.496*	-0.814**	1.000	0.010
	tt	0.393	0.011	0.010	1.000
Sig. (2-tailed)	*gencst*	-	0.000	0.016	0.064
	marg	0.000	-	0.000	0.961
	adjbal	0.016	0.000	-	0.963
	tt	0.064	0.961	0.963	-

** Correlation is significant at the 0.01 level (two tailed).
* Correlation is significant at the 0.05 level (two tailed).

Figure 1: Groups with an Interest in Electricity Industry Restructuring



Electricity Industry Restructuring Interests

Customers

- Residential
- Commercial
- Industrial
- Other

Special Interest Groups

- Low-Income Advocates
- Ratepayer Advocates
- Residential/Rural Interest Groups
- Trade Organizations
- Environmental Groups
- Sustainable Energy Advocates

State and Federal Government Agencies[1]

- U.S. Department of Energy
- Federal Energy Regulatory Commission
- Nuclear Regulatory Commission
- Environmental Protection Agency
- Securities and Exchange Commission
- Internal Revenue Service
- Department of Justice
- State and Local Government Agencies
- Public Utility Commissions

Utilities

- Investor-Owned Utilities
- Federally Owned Utilities
- Other Publicly Owned Utilities
- Cooperatively Owned Utilities
- Nonutility Generators

Financial Stakeholders

- Financial Institutions/Rating Agencies
- Shareholders and Investors
- Equity and Bondholders
- Research & Development Companies
- Equipment Manufacturers and Fuel Suppliers
- Power Marketers, Traders, and Brokers

[1] This is a partial list of State and Federal agencies with interests in the electricity industry.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

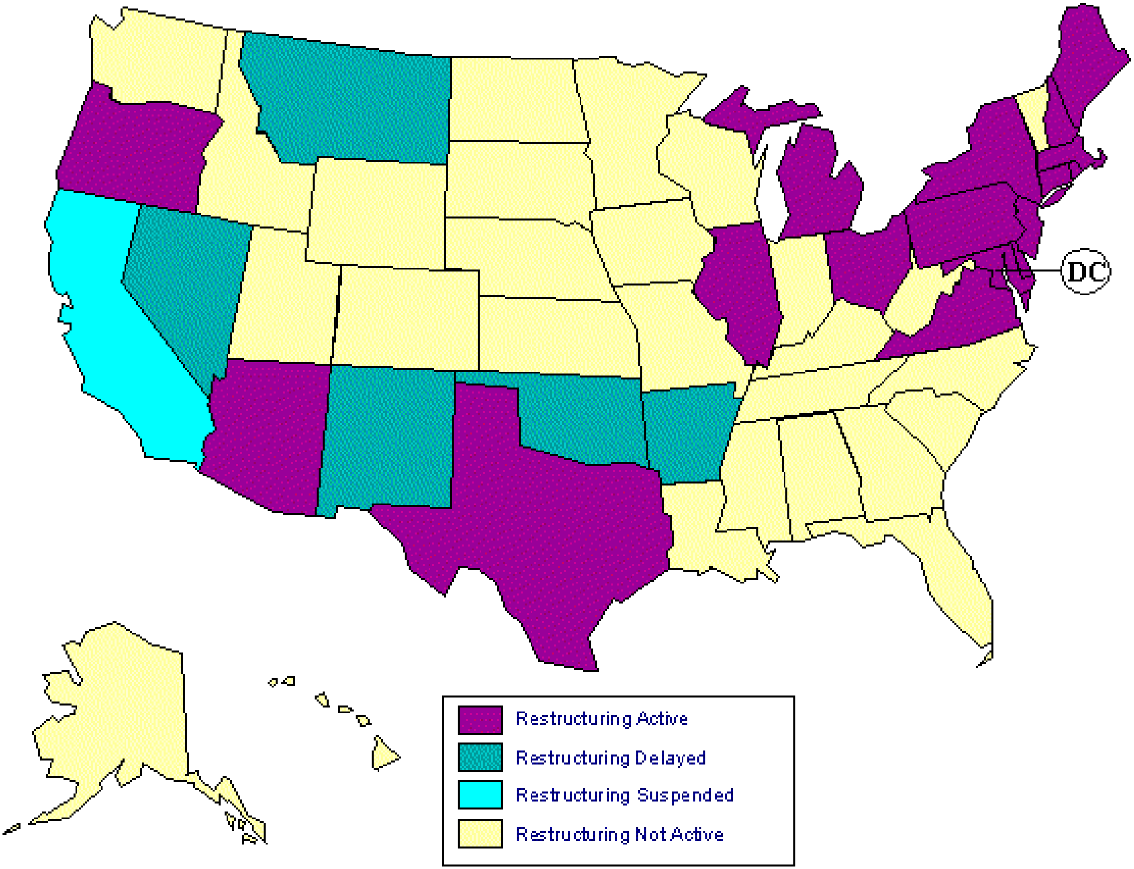
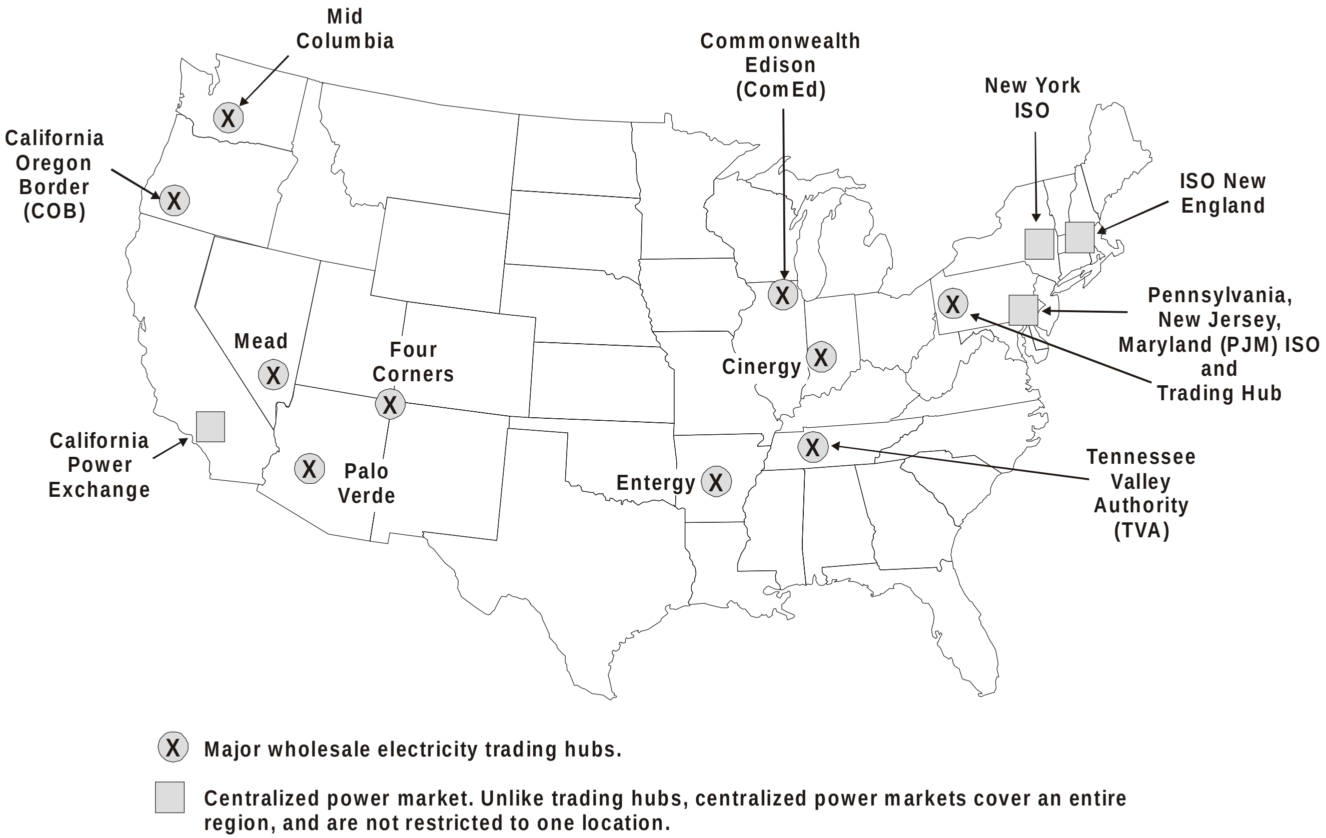

DC
Restructuring Active
Restructuring Delayed
Restructuring Suspended
Restructuring Not Active

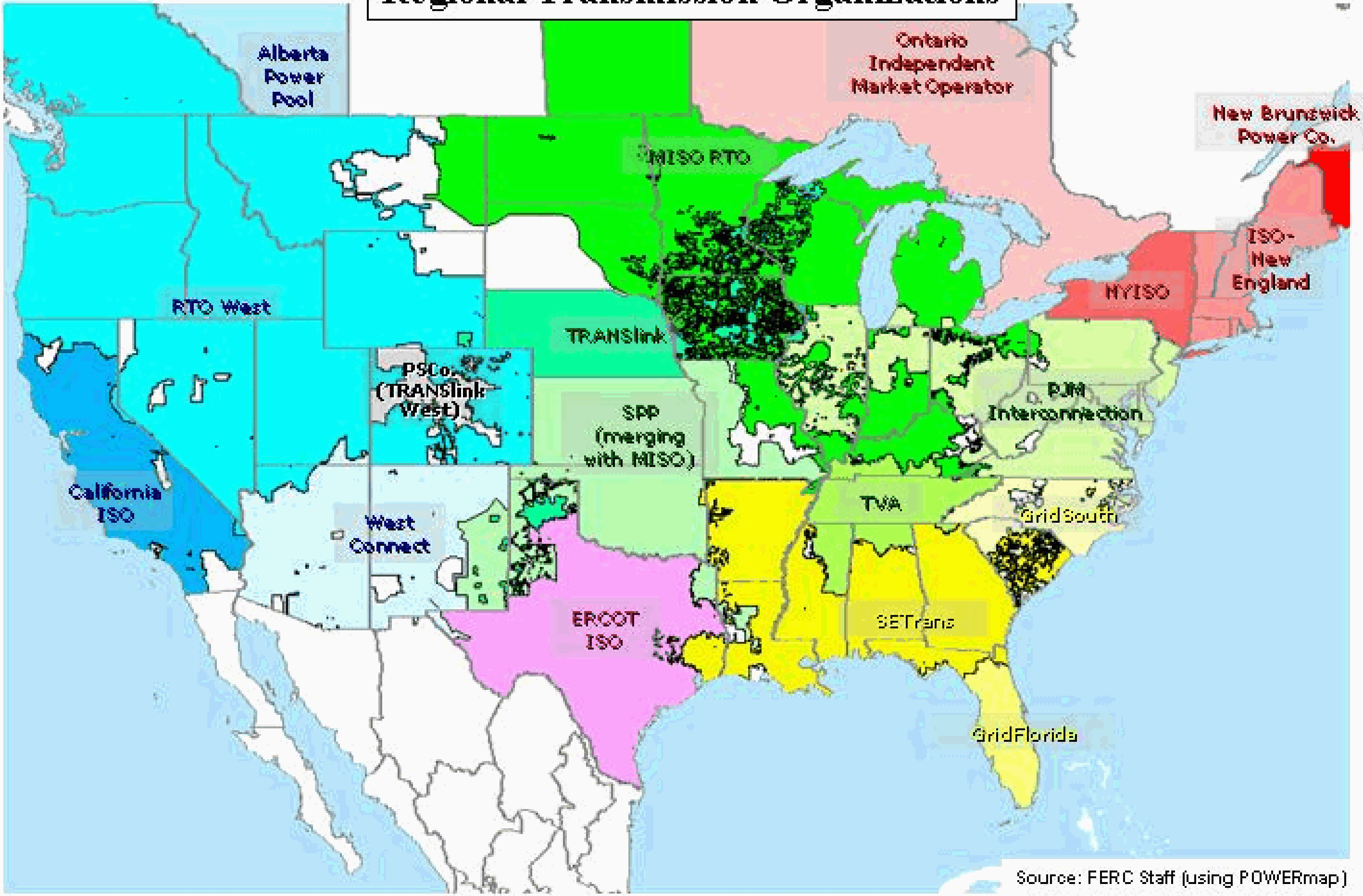
Figure 3: Major Wholesale Electricity Trading Hubs and Central Power Markets



Notes: Power trading also occurs at locations not indicated on the map. The New York Mercantile Exchange (NYMEX) has established electricity futures contracts for the Cinergy, COB, Entergy, Palo Verde, and PJM trading hubs. The Chicago Board of Trade has established electricity futures contracts for the ComEd and TVA trading hubs.

Source: Electric industry trade journals and Internet websites.

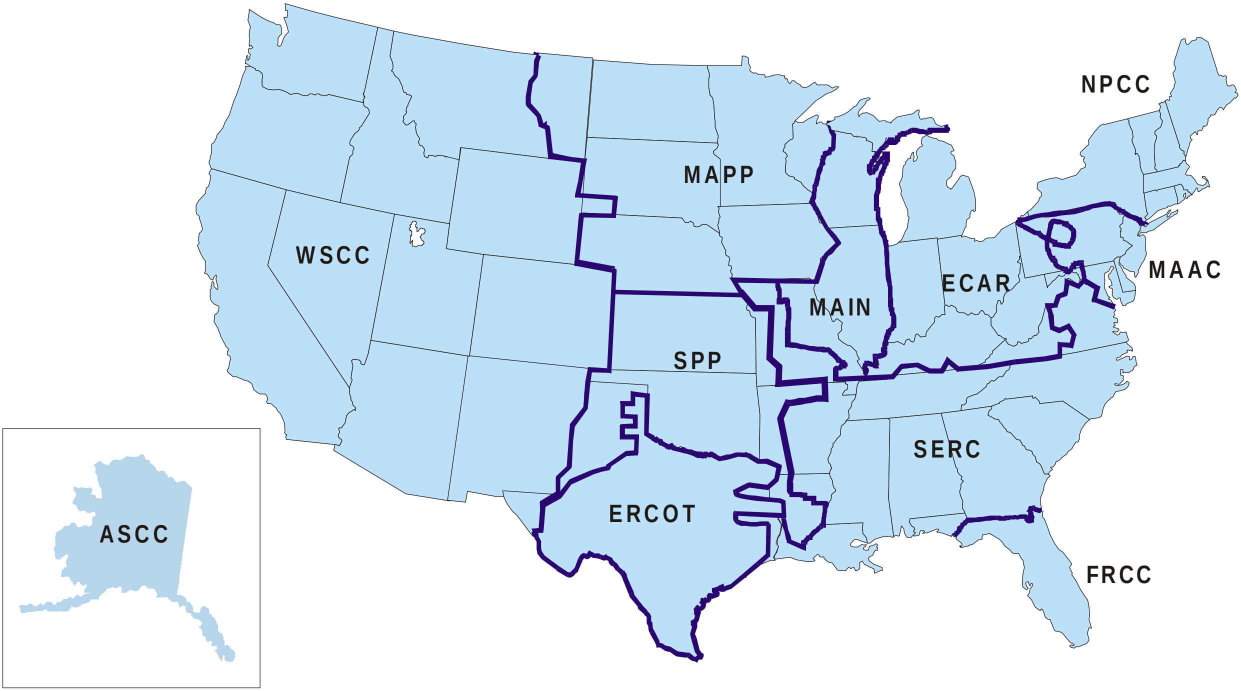
Regional Transmission Organizations



Source: FERC Staff (using POWERmap)

as of January 7, 2003

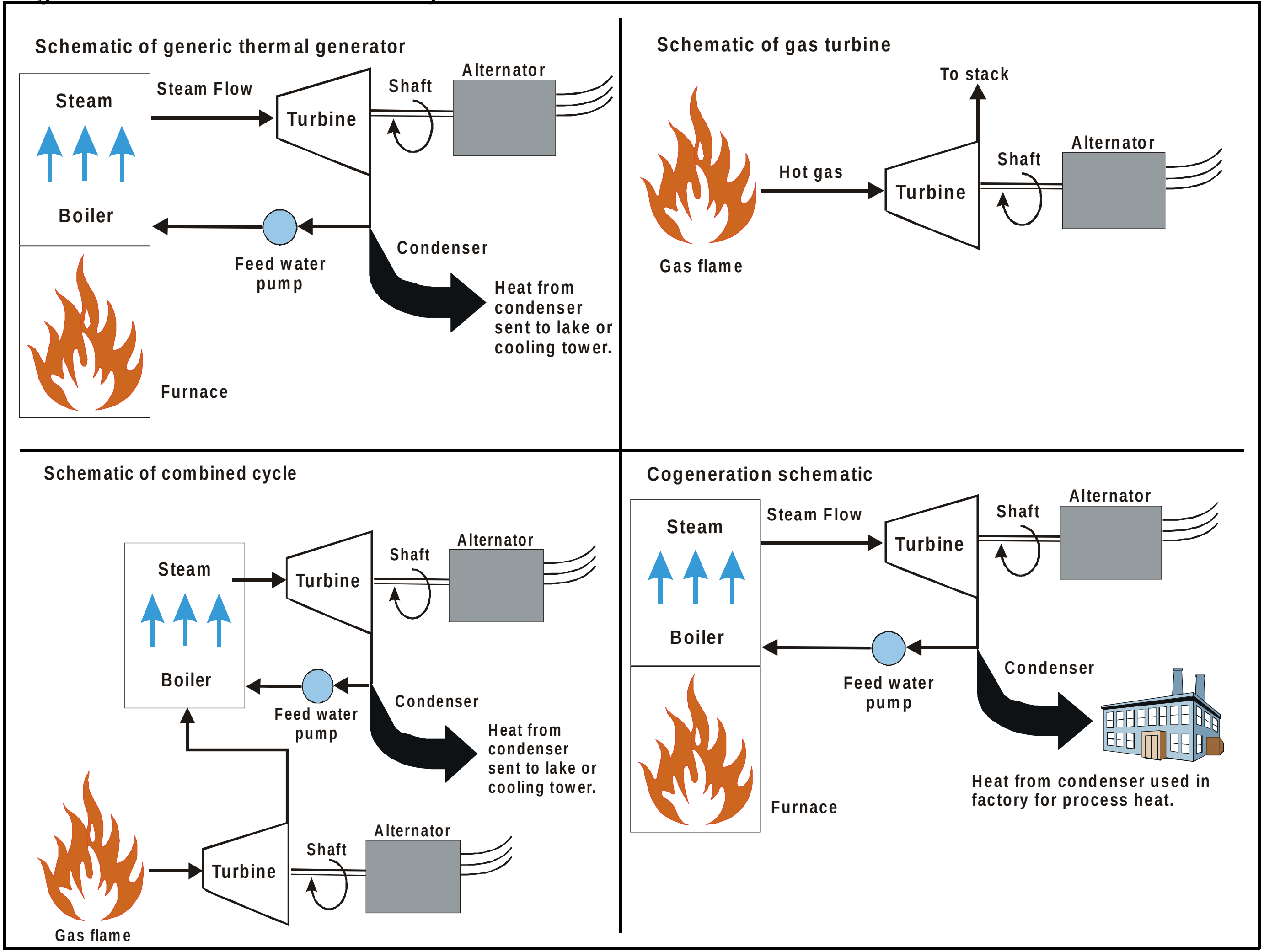
Figure 5: North American Electric Reliability Council Regions



ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas
FRCC - Florida Reliability Coordinating Council
MAAC - Mid-Atlantic Area Council
MAIN - Mid-America Interconnected Network
MAPP - Mid-Continent Area Power Pool
NPCC - Northeast Power Coordinating Council
SERC - Southeastern Electric Reliability Council
SPP - Southwest Power Pool
WSCC - Western Systems Coordinating Council

Note: The Alaska Systems Coordinating Council (ASCC) is an affiliate NERC member.
Source: North American Electric Reliability Council.

Figure 6: Prime Movers of Electricity



Source: R. Baldick, "Introduction to Electric Power Systems for Legal and Regulatory Professionals," Course Materials, The University of Texas at Austin (1999).

Appendix Two: Definitions

Base-load Plant -- A power plant, usually housing high-efficiency steam-electric units, that is normally operated to take all or part of the minimum load of a system, and that consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiencies and minimize system operating costs.

Capacity Benefit Margin (CBM) -- The amount of transmission-transfer capability reserved by load-serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM by a load-serving entity allows that entity to reduce its installed production capacity below a level otherwise necessary to meet its generation reliability requirements.

Capacity Reserves -- The amount of unused available capacity of an electric-power system at peak load.

Cogenerator -- A facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes. To receive status as a QF under PURPA, the facility must produce electricity and another form of useful thermal energy through the sequential use of energy, and meet certain ownership, operating, and efficiency criteria established by the FERC.

Combined Cycle -- A technology in which additional electricity is produced from otherwise lost waste heat exiting from one or more combustion-turbine generators. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of additional electricity. This process increases the overall efficiency of the electric-generating unit.

Combined-cycle Unit -- An electric-generating unit that consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust heat from the combustion turbine(s).

Competitive Pricing -- Pricing based on a competitive spot market. The price reflects the actual cost of producing the incremental unit of electricity at that instant, rather than the average cost over a period as with cost-of-service regulated pricing.

Congestion Pricing -- A system for pricing transmission service based in part on the instantaneous demand for transmission capacity.

Control Area -- An electric system that directly controls its production resources to continuously meet demand and fulfill exchange obligations, and that helps regulate and stabilize the frequency of its interconnection's electric voltage and current.

Cost-of-service Regulation -- A pricing concept traditionally used for designing electric-rate schedules. Rates are set so that the revenues from retail sales of electricity cover generation, transmission, and distribution costs plus a fair rate of return on invested capital.

Distributed Generation (DG) -- Electricity production located at the place of consumption, such as an industrial manufacturing facility, that employs diesel-motor, microturbine, fuel-cell, or other small-scale technology.

Energy Policy Act of 1992 (EPAct) -- Created the EWG, and granted the FERC authority to order eligible-party access to the interconnected transmission grid.

Exempt Wholesale Generator (EWG) -- An unregulated, non-utility power plant. "Exempt" means exempt from PUHCA restrictions and means in part that EWGs can be owned by unregulated subsidiaries of regulated IOUs, regardless of where the power plant is located.

Federal Energy Regulatory Commission (FERC) -- The federal agency that regulates the price, terms, and conditions of transmission services and electricity sold in interstate commerce.

Independent System Operator (ISO) -- A neutral operator responsible for maintaining an instantaneous balance of the grid system. The ISO performs its function by controlling the dispatch of flexible power plants to ensure that loads match resources available to the system.

Investor-owned Electric Utilities (IOUs) -- Utilities that earn a return for investors, regulated by state and sometimes the federal government.

Load -- The amount of electricity delivered or required at any specific point or points on a distribution system. The requirement originates at the energy-consuming equipment of the consumers.

Locational Marginal Pricing (LMP) -- Computational model that determines energy and congestion prices at specific transmission points based on optimal generating-unit dispatch and marginal production cost.

Merchant Plant -- An EWG that sells output into the wholesale power markets.

Natural Monopoly -- A situation in which one firm can produce a given level of output at a lower total cost than can any combination of multiple firms.

Non-utility Generator (NUG) -- An entity that owns electric-generating capacity and is not an electric utility. These privately owned entities produce electricity for their own use and/or for sale to utilities and others. NUGs include qualifying cogenerators, qualifying small power producers, and independent power producers without a designated franchise service area. This term is also used to describe a non-utility power plant.

North American Electric Reliability Council (NERC) -- A council, composed of ten regional councils, formed by the electric-utility industry to assure the reliability and adequacy of the bulk electricity supply in the electric-utility systems of North America.

Peak Demand -- The maximum load during a specified period of time.

Peaking Plant -- A plant usually housing low-efficiency steam units, combustion turbines, diesels, or pumped-storage hydroelectric equipment normally used only during peak-load periods.

Peaking Capacity -- Production capacity normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating units may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

Public Utility Commission (PUC) -- State regulatory agency responsible for regulating retail sales of electricity.

Public Utility Holding Company Act of 1935 (PUHCA) -- Federal law that prohibits acquisition of any wholesale or retail electric business through a holding company, unless that business becomes part of an integrated public utility system when combined with the utility's other electric business. The law also restricts ownership of an electric business by non-utility corporations.

Public Utility Regulatory Policies Act of 1978 (PURPA) -- Federal law that requires utilities to buy electricity from QFs at an avoided cost rate.

Qualifying Facility (QF) -- Refers to power plants qualifying under PURPA. To qualify, they must produce electricity with either cogeneration or renewables, and meet certain ownership, size, and efficiency criteria established by the FERC. Under PURPA, the local IOU is required to purchase the output of the QF at the IOU's avoided cost of production.

Rate Base -- The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash, working capital, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Real-time Pricing -- The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.

Regulatory Compact (or Contract) -- A theory which holds that in exchange for building the generation, transmission, and distribution infrastructure necessary to fulfill an obligation to serve all customers in a franchise service area, the utility is guaranteed a return on those investments.

Regional Transmission Organization (RTO) -- The term for an ISO as used in FERC Order 2000, which calls for transmission-owning utilities to give control of their transmission lines to RTOs.

Reserve Margin -- The amount of unused available capability of an electric-power system at peak load, as a percentage of total capability.

Spark Spread -- The price difference between fuel and electricity expressed in common thermal units. The spark spread provides an indication of whether it is profitable for a particular fossil generating unit to produce electricity at any point in time.

Stranded Costs -- For an IOU, costs that have been incurred to serve its customers and that were being recovered in rates, but under deregulation are no longer fully recoverable because of the availability of lower-priced alternative suppliers. It also reflects the difference between an IOU's revenues in the new competitive market and the cost of providing service, the latter of which includes the inherited fixed costs from the previous regulated market.

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