MAKING COMPETITION WORK: ADDRESSING ISSUES OF MARKET STRUCTURE AND MARKET POWER

Emerging Competition in the Electric Industry

Docket No. NOI-95-1

A Staff Analysis

March 1999

IOWA UTILITIES BOARD
IOWA DEPARTMENT OF COMMERCE

TABLE OF CONTENTS

GLOSSARY OF TERMS USED IN THE REPORT

Affiliate – A Person that directly, or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with another Person.

Aggregation – The process of combining Customers into a group for the acquisition of Competitive Electric Services.

Aggregator – A Person that combines Customers into a group and arranges for the acquisition of Competitive Electric Services without taking title to those services.

Alternative Provider – Providers of Competitive Electric Services that are not Incumbent Providers.

Ancillary Services – Services that must be purchased in conjunction with Transmission Service to maintain reliability of the Grid. These services include, at a minimum:

a. Scheduling, system control and dispatch – The Control Area Operator function that schedules generation operation functions before the fact. This also includes control of some generation in real-time to maintain generation/load balance.
b. Reactive supply and voltage control from generation sources – The introduction or absorption of reactive power from generators to maintain Transmission system voltages within required levels.
c. Regulation and frequency response – The use of generators equipped with automatic generation control to maintain minute-to-minute generation and load balance within the Control Area to meet NERC standards.
d. Energy imbalance – The use of generators to hourly match actual and scheduled transactions between Suppliers and their Customers.
e. Operating reserve – Spinning Reserve – Generators that are synchronized to the Grid, are available to take additional load, and can respond immediately to correct for generation/load imbalances due to generation and/or Transmission outages. Spinning Reserve is fully available in ten minutes.
f. Operating reserve – supplemental reserve – Generators and curtailable load that can be used to correct for generation/load imbalances due to generation and/or Transmission outages within ten minutes. Unlike Spinning Reserve, supplemental reserve is not required to respond immediately.

Assigned Delivery Service Area – A geographic area designated by the Board within which a Delivery Service Provider has the exclusive right to provide Delivery Services.

Bilateral Contract – A direct contract between a purchaser and a seller, including an intermediary.

Glossary of Terms Continued...

Billing Services – Billing and collection for Delivery Services, Ancillary Services, or Competitive Electric Services.

Board – The Iowa Utilities Board within the Department of Commerce created in IOWA CODE § 474.1.

Bundled Electric Service – Electric services provided as a consolidated package rather than as unbundled individual services.

Code of Conduct – A set of rules governing the relationship between a Delivery Service Provider and one or more of its Affiliates or Functionally Disaggregated divisions.

Comparable Service – Regulated services provided to third parties on the same or functionally equivalent basis, and under the same or functionally equivalent terms and conditions, as the regulated services provided by the Delivery Service Provider to itself, its Affiliates, or its Functionally Disaggregated divisions.

Competition – A market that has many potential buyers and sellers and no one seller or group of sellers of a commodity or service is able to control the price for that commodity or service.

Competitive Electric Services – Competitive Power Supply Services and all other electric Energy services sold at retail in Iowa on a competitive basis.

Competitive Electric Service Provider (CESP) – A Person providing Competitive Electric Services in Iowa.

Competitive Power Supply Provider – A Person that produces one or more elements of Competitive Power Supply Services in Iowa.

Competitive Power Supply Services – Electric Demand/capacity, Energy and Ancillary Generation Services sold at retail in Iowa.

Control – The possession, direct or indirect, of the power to direct or cause the direction of the management and policies of an enterprise through ownership, by contract, or otherwise.

Control Area – An electrical system bounded by interconnection (tie line) metering and telemetry. It controls its generation directly to maintain its interchange schedule with other Control Areas and contributes to frequency regulation of the interconnection.

Glossary of Terms Continued...

Control Area Operator – The Person that performs the scheduling, dispatching, system support, balancing and financial settlement functions related to the effective operation of the Control Area.

Corporate Disaggregation – The separation of the various functions (generation, Transmission Service, and Distribution Service) of a Utility into smaller, separate legal entities with different ownership. Utilities could divest themselves of their competitive assets either by selling them or by spinning-off of these assets (i.e., creating separate legal entities with separate stock).

Cost-Based Rates – Electric rates (either wholesale or retail) set on the basis of a Utility's actual cost of providing service. A regulatory body reviews the various cost inputs, and sets rates to recover the legitimate costs.

Customer – A Person that consumes or uses electric services.

Default Provider – The provider of Competitive Electric Services to a Customer that has not chosen a CESP.

Delivery Service – The transportation of electricity from one point on a Delivery Service Provider's Grid to another point on that Grid.

Delivery Service Provider – A person that provides Delivery Service in Iowa.

Demand – Electric power measured in kilowatts.

Deregulation – The elimination of regulation from a previously regulated industry or sector of an industry.

Disaggregate – To separate into component parts.

Dispatchability – The ability to "dispatch" or generate electricity from a plant on an as-needed basis.

Distribution Service – Delivery Service provided by facilities that are subject to the jurisdiction of the Board, board of an Iowa Electric Cooperative association, or city council or board of trustees of a Municipal Utility.

Divestiture – The requirement, either through legislation or regulation, for an owner to sell all or some specified portion of its generation assets.

Glossary of Terms Continued...

Economic Dispatch – Distribution of total generation requirements among alternative generator sources for optimum system economy taking into account both incremental generating costs and incremental Transmission costs.

Economic Efficiency – The optimal production and consumption of goods and services.

Economies of Scale – The increase in productivity or reduction in average cost of production, that arises from increasing all the factors of production in the same proportion. Economies of Scale occur where the industry exhibits decreasing average long-run costs with size of firm.

Economies of Scope – Economies achieved by producing multiple goods or services. Economies of Scope cause the average costs of large, integrated firms to be lower than the average costs of many small firms producing the same output.

Electric Cooperative – An electric Utility provider formed or organized as an Electric Cooperative under the laws of Iowa or elsewhere.

Electric Industry Restructuring – The process by which Customers have choice in many electric services as a result of Competition replacing price regulation of Competitive Power Supply Services and other electric services sold at retail in Iowa, with the exception of Delivery Services and Control Area operations.

Energy – Electric Energy measured in kilowatt-hours (kWh).

Federal Energy Regulatory Commission (FERC) – Regulates wholesale power and Transmission Service.

Flash-Cut – Permitting all Customers to have access to Competitive Electric Services at the same point in time.

Functional Disaggregation – The separation of the various functions of a Vertically-Integrated Electric Utility into smaller, separate divisions within the company. For example, Utilities could functionally separate (i.e., same company, but separate books) their regulated and competitive functions.

Grid – The interconnected assets (substations, poles, wire, transformers, etc.) that are used for the transportation of electricity. This includes assets used in Transmission or Distribution Service.

Glossary of Terms Continued...

Horizontal Market Power – The ability of a Person to control prices for a product or service as a result of the Person's control of the sources of supply for that product or service (i.e., generation).

Incumbent Provider – The provider of Bundled Electric Service to a customer on the day prior to the first Customer having access to Competitive Electric Services. All successor companies of the Incumbent Provider shall fall under this definition.

Independent System Operator (ISO) – An independent entity that polices, monitors, and has overall decision making authority over electric Transmission operations. The purpose of an ISO is to provide reasonable and equitable access to the Transmission system, to operate the Transmission system safely and reliably, and to prevent the Transmission system from becoming a factor in enhancing in an electricity market.

Load Profiling – The process of estimating the hourly Energy consumption for Customers that do not have Real-Time Meters. This is typically done by placing Real-Time Meters on statistical samples of Customers that are similar to the Customers being profiled. The average hourly Energy consumption pattern for the Customers included in the sample (the Load Profile) is assumed to apply to all similar Customers. The overall usage contained in an individual Customer's Load Profile is determined by adjusting for differences between the Customer's actual monthly Energy consumption and the average monthly Energy consumption of the sample group.

Marginal Cost – The projected cost of producing an additional unit or service; short-term Marginal Cost only includes costs that are variable over the short term; long-run Marginal Cost includes projected variable and fixed costs (i.e., it assumes all costs are variable over the long term).

Market Clearing Price – The estimated price per kilowatt-hour that an Incumbent Provider is presumed to receive from the competitive market for Demand and Energy made available as a result of a Customer purchasing Demand and Energy from a CESP other than its Incumbent Provider.

Market Power – A company's ability to increase profits by setting prices above competitive levels and restricting output below competitive levels in a particular market. Such prices reduce economic efficiency and cause inefficient transfer of wealth from the consumer to the producer.

Metering Services – Provision of a meter, meter maintenance and testing, or meter reading.

Glossary of Terms Continued...

Municipal Utility – A city enterprise engaged in the production, delivery, service, or sales of electricity established pursuant to IOWA CODE § 388. Municipal Utility includes a combined Utility system.

Open Access – The duty of the Delivery Service Provider to provide Comparable Service.

Order 888 – A 1996 rulemaking by the FERC that directs all private Utilities to provide nondiscriminatory Transmission access to other eligible parties and provides minimum standards for such service. Such service must be provided on the same basis as that which a Transmission owner provides itself. Order 888 also authorizes recovery of legitimate, verifiable, and non-mitigatable Transition Costs.

Person – An individual, partnership, business association, corporation (domestic or foreign), cooperative association, governmental entity, or political subdivision.

Phase-In – Permitting Customers to have access to Competitive Electric Services on a staggered schedule, with eligibility for each phase being determined by specific criteria or by random selection.

Poolco – An electric supply market where all generation suppliers are required to sell all or a portion of their output into a quasi-governmental purchasing pool, from which CESPs and Customers may purchase their requirements.

Provider of Last Resort – The designation of a Person responsible for providing Competitive Electric Services if no other Person willingly seeks to provide such service.

Real-Time Metering – Metering that records Customer usage on the same time frame as pricing changes in the market, typically hourly or more frequently.

Reciprocity – The requirement that CESPs allow Incumbent Providers to offer Competitive Electric Services to Customers serviced by such CESPs or their Affiliates.

Scheduling – The process by which an CESP or Incumbent Provider notifies the Control Area Operator of the amounts of Demand and Energy it intends to provide to the Grid on an hourly basis for a specified day, and the source(s) of that Demand and Energy.

Spinning Reserve – The reserve generating capacity connected to the electric system and ready to take load.

Glossary of Terms Continued...

Standard Offer Service – Bundled Electric Service subject to legislative and/or regulatory price constraints that is available to Customers during the Transition Cost Recovery Period.

Structural Disaggregation – The separation of the various functions (generation, Transmission, and Distribution) of a Utility into smaller, separate corporate subsidiaries still owned by the Utility. That is, Utilities could structurally separate the functions by formation of holding company structures, with separate corporate subsidiaries for monopoly and competitive functions.

Suppliers – All Persons providing generation services to Customers.

System Balancing – The responsibility of a Control Area Operator to make necessary changes in the output of the sources of generation under its control to maintain the required voltage and frequency of the Grid.

Transition Benefits – Benefits realized by the Incumbent Provider relating to generating units and purchased power contracts that have a greater market than booked value.

Transition Costs – All costs incurred by an Incumbent Provider as a result of changing from a regulated monopoly industry structure to a competitive market structure.

Transition Period – The period of time required for changing from a regulated monopoly industry structure to a competitive market structure.

Transmission Service – Delivery Service provided by facilities that are subject to the jurisdiction of the FERC.

Unbundled Rates – The separate charges for Competitive Electric Services, Transmission Services, and Distribution Services.

Unbundling – Disaggregating electric Utility service into its basic components of generation, Transmission, and Distribution and offering each discrete component separately for sale with separate rates for each component.

Utility – A Person owning or operating facilities for furnishing electric services to the public for compensation and subject to rate or service jurisdiction of the Board pursuant to IOWA CODE § 476.

Vertically-Integrated Electric Utility – Vertical Integration occurs when a single electric company, or its Affiliates, provide generation, Transmission, and Distribution Services.

Glossary of Terms Continued...

Vertical Market Power – The ability to favor one's own generation due to joint control of generation and Transmission or joint control of generation and the Utility purchasing function.

Wholesale Transaction – Sale of electricity from a Utility, independent power producer or power marketer to another similar entity.

EXECUTIVE SUMMARY

Customers will only benefit from choice in electric supply if the market is appropriately structured and market power issues are addressed. This report attempts to identify what the market should look like when all transition issues are resolved (i.e., the end-state). The report also addresses some of the transition issues that need to be resolved in order to achieve the desired end-state.

END-STATE ISSUES

The ultimate goal of Iowa's restructuring effort should be a robust competitive market in the provision of electric generation services for all customers and regions in Iowa. In order to achieve and maintain this goal, policymakers must identify: 1) what transactions will be allowed; 2) what services can efficiently be offered competitively; 3) how market power will be addressed; 4) what regulation of affiliate transactions is needed; and 5) what siting requirements are relevant in a competitive generation market.

Allowable Transactions: Three market structures have been advanced in other states and throughout the world: poolco, direct access, and combined poolco/direct access. Allowable transactions change with the market structure selected. The direct access and combined approaches allow for direct contracting between a customer and a competitive electric service provider (CESP). The poolco structure requires all power to flow in and out of a centralized power pool. The less restrictive the market, the more likely policymakers will select a direct access or combined approach.

Competitive Provisioning of Services: The Board's principles state that regulatory policies should encourage competition where fair and efficient competition promotes the public interest. Electric restructuring, by definition, provides for competitive provisioning of generation services. Most stakeholders agree delivery systems (which include transmission and distribution services) cannot be efficiently provided through a competitive market. Continued monopoly control of delivery services requires comparable and nondiscriminatory access on the grid for all CESPs.[1] In addition, the Board must continue to regulate rates for customers for transmission and distribution services not regulated by the Federal Energy Regulatory Commission (FERC).

Stakeholders have also raised the possibility of having competitively-provided control area operations, ancillary services, and customer services (such as metering and billing services). The control area operator keeps the system in balance and provides all functions needed to make the system work. Competitive bidding for control area operations has occurred in the wholesale market and may be possible for large customers in the retail market. Control area operators also provide ancillary services. These services are integral to the reliable operation of the interconnected electric system. The FERC has concluded that all but two ancillary services (i.e., system control and voltage support) can be competitively provided. Although it may be possible to competitively provide ancillary services other than system control and voltage support, issues concerning location, costing, free-riders, and metering service need to be addressed.[2] While metering and billing services for large customers may easily be provided on a competitive basis, economies associated with small customer metering and billing services may eliminate any efficiencies gained from competitively providing these services.

Open access for generation services does not ensure a competitive market. Price deregulation of monopoly essential services should be avoided, particularly if

---

[1]The grid is defined as the interconnected assets (substations, poles, wire, transformers, etc.) that are used for the transportation of electricity. This includes assets used in transmission and distribution.

[2] These issues are developed in the body of the report.

barriers to entry exist. Options for determining when prices should be deregulated include: 1) Board determination after a showing of effective competition; 2) date-certain price deregulation (e.g., one day after a pre-defined transition period); or 3) Board determination after a showing that all unreasonable or artificial barriers to entry have been removed.

Market Power: Market power is the ability of one firm or a group of firms (acting in concert) to control market price or entry. Iowa's incumbent providers have vertical market power in providing generation service because they control the delivery system (i.e., transmission/distribution facilities). Horizontal market power exists when one utility owns enough generation in the region to control market price. The existence of market power does not imply abuse of that power.

Some states have taken significant preemptory initiatives to mitigate the potential for market power abuse. The most significant of these initiatives is mandatory divestiture (or sale) of all or a portion of the vertically-integrated incumbent's generating capacity. States ordering mandatory divestiture have concluded the economic costs of divestiture (including lost economies of scope, tax exposure, and possible financing concerns) are outweighed by the efficiencies gained by preempting potential market power abuses.

States not ordering divestiture have, at a minimum, ordered vertically-integrated utilities to functionally separate regulated transmission and distribution services (i.e., delivery) from competitive generation and marketing services. These states have also typically required the utility to turn over control of its transmission facilities to an independent system operator (ISO). Conceptually, ISOs provide for reasonable and equitable access to a safe and reliable transmission system, while preventing the transmission system from becoming a vehicle to enhance market power. ISO membership requires a workable ISO in the market region. While two ISOs are developing in the midwest (Mid-Continent Area Power Pool and Midwest ISOs), neither is acceptable to all of Iowa's utilities. Joint ownership of transmission facilities makes it imperative Iowa's utilities join the same ISO.[3]

Other remedies to potential market power abuse include prohibiting affiliate use of the parent utility's corporate name and logo, regulatory oversight of mergers, and market monitoring. The fewer restrictions placed on incumbent vertically-integrated utilities, the greater the need for monitoring. If market power abuses are preventing competitive entry and pricing, administrative remedies should be available to mitigate this abuse. The ultimate remedy (i.e., divestiture) could be reserved for legislative action after the transition period.

Affiliate Transactions: The presence of several buyers and sellers facilitates a competitive market. This includes affiliates of regulated utilities. The inherent incentives for utilities to subsidize competitive services with regulated revenues invites regulatory scrutiny. In the past, several behavioral remedies have been used by regulators to police affiliate transactions. These remedies include: 1) requiring access to the books and records of non-regulated affiliates; 2) auditing; 3) having standard cost allocation principles and manuals; and 4) regulating cost treatment for affiliated transactions. In a restructured industry, the importance of regulatory oversight of affiliate transactions increases because profit potential is enhanced and the vertically-integrated utilities provide essential services (i.e., transmission/distribution services) to competitors. To prevent anti-competitive behavior, states (not requiring divestiture) have put in place strict codes of conduct which govern the relationship between the regulated delivery function and the competitive generation and marketing functions.

Siting: The Board currently provides the administrative mechanism for generation

---

[3] Alliant has indicated its intent to join the Midwest ISO.

and transmission plant siting proceedings. While the environmental requirements remain relevant for generation plant siting in a restructured environment, the demonstration of need and least-cost planning requirements invite revision. Need and least-cost planning requirements are the only issues which distinguish utility and non-utility generation plant siting requirements under current Iowa law. Transmission siting requirements continue to be relevant in a restructured industry.

TRANSITION ISSUES

The transition issues addressed in this report which must be resolved in achieving the desired end-state include: 1) price protections for customers until markets develop (i.e., standard offer service); 2) the timeframe for introducing customer choice (i.e., phase-in versus flash-cut); 3) which CESPs can serve Iowa's markets (i.e., reciprocity); 4) the provision of price information such that choice is facilitated (i.e., rate unbundling); and 5) treatment of existing contracts for customer loads.

Standard Offer Service: Standard offer service implies the bundled utility service with which customers are familiar. Standard offer service is typically provided by the default provider during the transition period to all customers not actively choosing a CESP. The default provider can be determined through competitive bidding or designation. Most states have designated the delivery service provider as the default provider during the transition period.

Phase-In Versus Flash-Cut: Open access can be phased-in over a pre-determined time period or instituted for all customers on some date-certain (i.e., flash-cut). The phase-in could be a percentage of load or customers, with a portion of all classes included in each phase. A flash-cut would allow choice for all customers at the same time. The approach used to introduce open access is not as important as allowing enough time for incumbent provider systems to adjust their billing and customer service systems to accommodate choice.

Reciprocity: Reciprocity requires utilities wanting to compete in Iowa's retail market to open their service territories to competition under similar conditions. Absence of a reciprocity requirement would benefit Iowa's consumers, because low-cost providers in states which have not restructured (e.g., Wisconsin, Nebraska, etc.) could serve Iowa's retail market. Reciprocity could, however, increase stranded cost exposure by restricting the markets in which Iowa's incumbent providers could compete. In-state reciprocity may require some Board oversight of the delivery service rates charged by incumbent municipal electric utilities and electric cooperatives to prevent discriminatory practices.

Rate Unbundling: Rate unbundling separates the bundled rate component into its various functions: generation, transmission, distribution, and customer services. Customers must know their current generation rate for comparison purposes with other competitive offers. Unbundling could be done in a contested case proceeding under the Board's current legislative authority.

Contracting: Existing contracting for customer load could discourage CESPs from entering Iowa's retail market. Policymakers may want to consider allowing for renegotiation of current contracts and service agreements to encourage competitive supply.

1.0 INTRODUCTION

The ultimate goal of any restructuring effort is the emergence of a robust regional competitive market in the supply of generation for all customers. Removing the exclusive service territories in Iowa may not be sufficient to prompt this regional market. Issues of market structure and power require review. It is also important to have a clear understanding of the end-state. In other words, what do policymakers want the market to look like when all the transition issues are resolved. In addressing the end-state, policymakers must decide what transactions will be allowed, how competitive markets will be identified and encouraged, how market power abuses can be minimized, what restrictions will be placed on affiliate transactions, and what generation and transmission siting requirements remain relevant. Once the end-state is defined, transitional measures, needed to achieve that end-state, must be put in place. Transitional issues addressed in this report include: standard offer service, phase-in versus flash-cut, reciprocity, rate unbundling, and contracting.

The report begins by addressing end-state issues including allowable transactions, competitive provisioning of services, options for addressing market power, and requirements placed on affiliate transactions and plant/transmission siting. The second half of the report details transition issues (not related to incumbent transition costs/benefits) which must be addressed to achieve the desired end-state.

A summary of comments submitted by members of the Docket No. NOI-95-1 Advisory Group, responding to the earlier draft version of this report, is attached as Appendix E.

2.0 END-STATE ISSUES

End-state issues fall into six broad categories: 1) Customer Focus Issues; 2) Market Power Issues; 3) Market Structure Issues; 4) Reliability; 5) Public Benefits; and 6) Customer Education. The Board's Action Plan for Electric Restructuring (Action Plan) assigned all of these end-state issues to various staff teams. The Corporate and Market Structure Teams were charged with addressing the following end-state issues which fall under the broad categories of market power and structure:

- **Allowable Transactions**
- **Competitive Provisioning of Services**
- **Market Power**
- **Affiliate Transactions**
- **Siting Authority and Requirements**

2.1 ALLOWABLE TRANSACTIONS

The type of transactions allowed in a restructured electric industry depends on the market structure selected. The Board's Action Plan identified the advantages and disadvantages of three different market structures as follows:[4]

1) Poolco Structure:

   Advantages:

   - Maintains the efficiencies of economic dispatch;
   - Leads to transparent market prices;
   - Increases liquidity in the spot market;

   Disadvantages:

[4] These conclusions were based on extensive research and analysis completed in staff's third report in Docket No. NOI-95-1: "Regulatory and Restructuring Options in the Electric Utility Industry (A Staff Analysis)," January 1997.

- Fails to provide customers full retail choice;
- Encourages game-playing with spot-market prices;
- Requires a regional approach to electric restructuring (i.e., an Iowa-only poolco is not workable);

2) Direct Access Structure:

   Advantages:

   - Provides customers a choice of retail generation suppliers;
   - Allows large-volume customers to negotiate agreements which best meet their individual reliability and service needs;

   Disadvantages:

   - Risks the efficiencies realized through economic dispatch;
   - Leads to market prices which are not transparent;
   - Advantages large-volume customers over small-volume customers if load aggregators are absent from the market;

3) Combined Poolco/Direct Access Structure:

   Advantages:

   - Allows large-volume customers to negotiate for power supplies based on individual reliability and service needs;
   - Allows for a spot market where small-volume customers can purchase power without the assistance of an aggregator or power marketer;
   - Benefits small producers by allowing them to sell their power directly to the spot market;

   Disadvantages:

   - Adds complexity to the market and possible costs to implementing electric restructuring;
   - Risks the efficiencies realized through economic dispatch; and
   - Requires regional cooperation in developing a spot market.

Bilateral contracting between a customer and generator is not allowed under a poolco structure.[5] All generation flows into and out of the poolco. The market clearing price is determined by the bid price of the last unit dispatched during a given time interval. As such, a generation supplier can increase the price paid to all units by bidding up the price of the last unit dispatched or by withholding capacity. This type of price manipulation results when one supplier owns enough generation in the market to control the dispatch order. For this reason, an Iowa-only poolco is unworkable because two utilities (MidAmerican Energy Company and Alliant Utilities) own the majority of generating capacity within the state.

The direct access market structure provides for bilateral contracting at the exclusion of a poolco. Transaction costs involved in bilateral contracting may preclude small customers or CESPs from participating in the market under the direct access structure. This is particularly true if aggregators do not materialize in Iowa's market.

The third market structure combines a poolco with bilateral contracting. Under the combined structure, a poolco provides a market mechanism for small customers and generation suppliers, without precluding the flexibility of bilateral contracting. California advanced the combined approach by allowing bilateral contracting alongside a state-ordered poolco or power exchange.[6] The state-ordered power exchange in California has discouraged competitive suppliers because, in many instances, more money can be made selling to the exchange than directly contracting with CESPs.[7]

Markets usually respond to need. If small customers or CESPs require a means to participate in the market, that market will likely respond through aggregation or the

---

[5] Bilateral contracting refers to the direct contracting between a generator and user, or intermediary, outside of a centralized power pool.

[6] Under California's restructuring law, AB 1890, utility distribution companies must bid all generation into the power exchange and purchase all energy needs out of the power exchange during the transition period. This same requirement does not apply to alternative providers.

[7] Robert McCullough, "California's Electricity Market: Are Customers Necessary?," Public Utilities Fortnightly, July 15, 1998, p. 37.

creation of voluntary power exchanges.[8] Control area operators could easily perform power exchange functions on a voluntary basis. Bilateral contracting in the market mitigates the ability of incumbent providers to control the price resulting from an exclusive control area power exchange.

Determining the best market structure for Iowa depends, in part, on the emergence of aggregators in the state. Determining the potential for aggregation is one goal of the residential and small commercial pilot initiated by the Board as part of its Action Plan.[9] The pilot project was filed by MidAmerican Energy on May 4, 1998. The earliest implementation date is second quarter - 1999. Appendix A provides the basics of the residential/small commercial pilot.

2.2 COMPETITIVE PROVISIONING OF SERVICES

The Board's Principles state:

> Where fair and efficient competition promotes the public interest, regulatory policies should encourage competition. Regulation must continue for monopoly services to ensure stakeholders fair and nondiscriminatory treatment.

This section of the report attempts to address this principle by defining:

- what existing utility services can efficiently be provided competitively in the initial market configuration;
- when price regulation is no longer needed; and

---

[8] Aggregation is the process of combining customers into a group for the acquisition of competitive electric services.

[9] The Board's Action Plan called for the creation of an Iowa-specific pilot project allowing retail open-access in order to, at a minimum, obtain information pertaining to:

⇒ consumer acceptance and understanding of retail choice;
⇒ potential benefits and costs of load aggregation in Iowa;
⇒ customer information needs and ways to meet those needs;
⇒ need for (and alternatives to) individual time-of-use meters; and
⇒ types of services which can efficiently be provided competitively to each customer class.

- a process for continual review of utility services.

Initial Market Configuration

Initial configuration of the competitive market would involve selecting existing utility functions, such as generation, for which open access or competitive entry could reasonably be granted through electric restructuring legislation. The following functions/services were reviewed when determining the initial market configuration:

- Generation
- Transmission/Distribution (a.k.a. Delivery)
- Control Area Operations (including Ancillary Services)
- Metering and Billing Services

These functions are described below.

Generation: By definition, an electric restructuring law would allow for the competitive provisioning of generation services from alternative providers. The terms "aggregator," "CESP," and "alternative provider" are used in this report to define new entrants in the generation market.[10] Allowing new entrants into the generation market is not sufficient to ensure a competitive generation market. The market power considerations discussed in the next section could inhibit or delay the emergence of a competitive market and price. In addition, some customers or customer classes may not attract alternative providers, because it is not profitable to serve them. A provider of last resort designation may be necessary to ensure all customers are served. Tying the functions of default provider and provider of last resort is one option for ensuring all customers have access to a provider of generation services. (See the Universal Service Team

[10] Aggregators combine the electric load on behalf of a group of customers and arrange for the sale and purchase of electric power. The aggregator does not take actual title to the power. Alternative providers either generate electricity to sell to retail electric customers or take title to power generated by another supplier.

Report).

Transmission/Distribution (a.k.a. Delivery)*:* The Board's Action Plan concludes:

- The existing service area boundaries should be maintained (at this time) for the provision of distribution services under a restructured electric utility industry in order to:
  1. limit duplication of wires facilities;
  2. enhance the ability to plan for increased reliability;
  3. lead to more efficient dispute resolution;
  4. maintain a more localized approach for system expansion;
  5. provide for a transitional carrier of last resort; and
  6. prevent uneconomic competition (resulting solely from regulated pricing mechanisms) in the provision of new distribution facilities.[11]
- A competitive market structure which allows customers to choose their generation provider requires open access on the state's distribution system.

Most stakeholders agree assigned delivery service areas for distribution service should be maintained. Bypass of the distribution system in these assigned delivery service areas would not be allowed unless permitted by the assigned delivery service provider.

Comparable and nondiscriminatory access to the incumbent's transmission/distribution system is essential to a competitive market. To ensure this access, policymakers could require delivery service providers to adopt CESP-friendly policies that minimize transaction costs. Such policies could include providing for the use of load profiling rather than real-time metering for

---

[11] The IOWA CODE currently permits utilities to voluntarily allow third parties to construct distribution facilities within their exclusive service territories.

small customers. Real-time metering is expensive and, therefore, a potential impediment to market participation by small customers. The main benefit of real-time metering is in providing CESPs hourly customer load information for meeting their scheduling and balancing requirements, in terms of matching their generation deliveries with their customers' usage. Load profiling is based on historical customer class usage patterns and, thus, may provide less accurate information. On balance, any lower accuracy will tend to make CESP balancing payments to the incumbent provider more expensive, which will translate into higher generation prices for small customers. However, for small customers, any higher generation prices should be more than offset by meter cost savings.[12] Given incumbent provider policies that provide for the use of load profiling, metering economics and customer choice will likely determine the extent of real-time metering usage.

Ensuring access could also mean requiring utilities to charge reasonable, cost-based fees for providing metering data, billing services, and changing a customer's CESP. Results from MidAmerican Energy's direct access pilot program for residential and small commercial customers might provide additional information about what encourages or discourages market participation by CESPs and customers (see Appendix A).

Another issue involved in the monopoly provisioning of delivery services is continued regulation of terms, rates, and conditions. All states which have or are in the process of restructuring have continued to regulate the terms, rates, and conditions of the distribution function to customers. Some parties in Iowa's restructuring debate have suggested simplifying the distribution company's role

---

12

in providing delivery (i.e., transmission and distribution) services, by allowing them to sell delivery to CESPs for resale, rather than directly to customers. This arrangement could be termed delivery reselling. In effect, the CESP would become the delivery service provider's customer and end-use customers would become the CESP's customers for all services. The main problem with this approach is that it effectively severs the direct relationship between customers and the delivery service provider. This could create customer confusion and blur lines of accountability when problems with delivery occur. In addition, delivery reselling creates a significant advantage for the incumbent, vertically-integrated provider. The incumbent provider could market itself as a "full-service" provider which provides both generation and delivery services. CESPs would be placed in the potentially untenable position of being responsible to end-use customers for their delivery service, yet having jo direct0.03wer to solve delivery problems.

Ajother problem with delivery reselling is that it might result in cost shifting among customer classes. Currently, the incumbent provider's bundled customer class rates are designed according to regulated cost allocation studies. Unregulated CESPs would jot be bound by these studies and could re-price the incumbent utilities' delivery services among customer classes in any manner they choose. One of the main purposes of regulatory involvement in rate unbundling would be to ensure that cross-subsidization among customer classes does jot occur. (See Rate Unbundling Section).

Delivery reselling has the advantage of allowing customers to receive one bill for all services from the CESP. Customers would also receive one bill if CESPs were allowed to purchase billing services from the incumbent provider at incremental cost. Customers would receive one bill for all services, from the incumbent provider, similar to the one-bill arrangement between local telephone companies and long distance providers. Another alternative, based on current incumbent provider practice, would allow customers to designate willing CESPs as their paying agents for transmission and distribution services. Recognizing that a one-bill option is important to customers, an effectively competitive market should have the flexibility to provide it. The CESP paying agent would be responsible for payment to the incumbent provider, and customers would be responsible for payment to their CESP paying agents. Under this option, the direct relationship between the incumbent delivery service provider and retail customer is preserved, which is not the case under delivery reselling. The retail customer would remain the incumbent delivery service provider's customer of record and continue paying regulated class delivery rates. This approach is being used in MidAmerican Energy's retail access pilot program for residential and small commercial customers. (See Appendix A).

Control Area Operations (Including Ancillary Services): Control area operations and associated ancillary services have traditionally been provided by vertically-integrated utilities as part of providing electric service. These utilities own and operate generators, transmission, and control areas. In the regulated retail environment, generators produce kilowatt-hours and control centers use real-time information to provide ancillary services. Electric utilities interconnect with each other for reasons of reliability and economy. To share the benefits of the interconnected system, each incumbent provider is expected to meet its obligations of matching its generation with its load, maintaining interconnection power flows at scheduled levels during normal operating conditions, assisting neighbors during periods of need, and participating in the frequency stability[13] of

[13] Frequency stability depends on the match between load and generation on-line. If there is a sudden failure of a large generator or transmission line when the system load is high, the remaining generators get overloaded and start slowing down. As a result, the frequency drops. This must be corrected within seconds or the utility will fall out of synchronism with the rest of the system and may eventually get disconnected from the system.

the system.

All interconnected electric systems use one or more control areas. A control area is defined as that portion of the interconnected system to which a common generation control scheme can apply. This means that a control area is expected to regulate (monitor and adjust) its generation to follow its own load changes. In a "single-area system," one control system regulates the entire interconnection. A "multiple-area system" has many control areas, each with its own control system and each adjusting its generation in response to its load changes within its own area. All the major interconnected systems in the United States have multiple-area systems. Monitoring the flow of power over interconnections (ties) between areas determines whether a particular area is satisfactorily absorbing all load changes within its boundaries.

FERC Order 888, issued in 1996, unbundled generation from transmission and identified ancillary services. FERC defined ancillary services are those necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas[14] and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. The term ancillary services is somewhat misleading. Ancillary services are not supplementary services, they are integral in providing reliable operation of the interconnected electric system. The overall cost of ancillary services ranges from 6 percent to 20 percent of total generation and transmission costs, totaling about $14 billion a year.[15] As such, these services need to be accurately defined, measured, and priced.

FERC Order 888 required the following six ancillary services be included in the

[14] Appendix B summarizes NERC control area obligations.
[15] B. Kirby and E. Hirst, Ancillary Service Costs For 12 U.S. Electric Utilities, Oak Ridge National Laboratory, ORNL/CON-427, March 1996.

utilities’ open-access transmission tariffs:

- Scheduling, System Control, and Dispatch Service
- Reactive Supply and Voltage Control From Generation Source Service
- Regulation of Frequency Response Service
- Energy Imbalance Service
- Operating Reserve-Spinning Reserve Service
- Operating Reserve-Supplemental Reserve Service

These services are defined in Appendix B. In addition, transmission providers may provide loss compensation service as an ancillary service to transmission customers.

The FERC further clarified that the transmission provider operating the control area is uniquely positioned to provide system control and voltage services. As such, these services can only be provided by the local control area. With respect to the remaining four services, the FERC only requires transmission providers to <u>offer</u> these services. Transmission customers can obtain these services in any of three ways: from the transmission provider, from another source, or by self-provision.

Several issues need to be addressed before ancillary services can be unbundled and provided on a competitive basis:

1) Location Where Ancillary Services are Needed - Certain ancillary services will only be needed in the area in which the load is located even if the receipt and delivery points are in different control areas. This is especially true for reactive supply and voltage support services which must be provided where needed.

2) Cost Allocation - State commissions must design cost allocation methods

that do not recover costs associated with FERC-jurisdictional transmission services once retail direct access is provided on an unbundled basis.

3) Free-Riders - Without an independent system to monitor the provision of ancillary services, transmission service purchasers may become free riders on the transmission system and could potentially adversely affect the reliability of the interconnected electric system.

4) Additional Metering - The types and amounts of metering required to unbundle generation and transmission is important. Today's metering focuses on the control area as the unit of observance. Additional metering may be needed to measure real-time output of generators and electric usage of individual loads. Ancillary service billing, accounting, and measurement will depend partly on costs and availability of metering equipment.

5) Costing - The costs of providing ancillary services are difficult to quantify. In the past, the variable costs of providing the ancillary services were bundled into the overall cost of providing electricity. Costing is complicated, because the same equipment (e.g., generator) can provide different services at different times, different generators can supply different amounts of ancillary services, and different customers require different ancillary services. For example, if a generator's output is being used for operating reserve, the generator cannot be used to supply additional retail load. The cost, in this example, is the revenue associated with forgone sales. Because utilities have traditionally provided ancillary services as a bundled service, they only have limited knowledge of the costs associated with providing these services. Also,

since several of the ancillary services primarily support the entire electric system, they cannot be readily associated with individual transactions.

Finally, some transmission-owning utilities with embedded cost tariffs argue it is unfair for the FERC to allow customers to purchase ancillary services from other than transmission providers. These transmission providers believe, when market prices are lower, customers will purchase these services elsewhere, placing them at a competitive disadvantage. Others believe that competitive markets will develop quickly and the embedded-cost tariffs will then be replaced by market-based prices.

Metering and Billing Services: Policymakers could reasonably allow CESPs and incumbent providers to competitively provide metering and billing services to customers during the transition period. CESPs would be allowed to provide meters, meter reading, and billing for all services, and forward delivery service payments to the incumbent provider. The economics of CESP scheduling and balancing requirements make it possible that CESPs may require large customers to use special real-time telemetering that meets CESPs' specifications. Special metering and billing services can be offered in conjunction with other potentially profitable services such as energy management. However, there may be problems responding to customer meter complaints if the CESP does not have an Iowa presence. Also, for safety purposes, the delivery service provider may require meter access for disconnections.

At the same time, policymakers should consider requiring incumbent delivery service providers to continue providing default meter, meter reading, and billing services at regulated rates. This requirement provides customers price protection if effective competition does not develop for their metering and billing services. This requirement also recognizes that incumbent delivery service providers may enjoy significant economies of scale in providing metering and billing services to a broad base of customers. In other words, these services may be more efficiently provided by a regulated monopoly entity. For example, having a meter read once by the incumbent delivery service provider is more efficient than having both the incumbent provider and CESP read the meter. It is also important to remember the incumbent delivery service provider's meter reading data make possible the load research necessary to provide load profiling for customers. These data also provide useful information for control area operations. Most states require restructured utilities to continue providing metering and billing services as part of their regulated delivery function.

Price Deregulation

Granting competitive open access for a service would not necessarily be the same as deregulating it. Price deregulation could be predicated on a showing that effective competition exists for the service. Effective competition exists if no firm or group of firms controls service price. For example, a showing of competition in generation would mean discontinuance of standard offer service. (See Section on Standard Offer Service).

An example of such a process can be found in current Iowa law governing Board regulation of telecommunications. IOWA CODE § 476.1D (1997) Regulation and Deregulation of Communications Services states:

> 1. . . . [T]he jurisdiction of the board as to the regulation of communications services is not applicable to a service or facility that is provided or is proposed to be provided by a telephone utility that is or becomes subject to effective competition, as determined by the board. In determining whether a service or facility is or becomes subject to

> effective competition, the board shall consider, among other factors, whether a comparable service or facility is available from a supplier other than the telephone utility and whether market forces are sufficient to assure just and reasonable rates without regulation . . . .
>
> 5. Notwithstanding the presence of effective competition, if the board determines a service or facility is an essential communications service or facility and the public interest warrants retention of service regulation, the board shall deregulate rates and may continue service regulation.
>
> 6. The board may reimpose rate and service regulation on a deregulated service or facility if it determines the service or facility is no longer subject to effective competition.

The Board implements this statute according to procedures described in IOWA ADMIN. CODE § 199-5 Procedure of Determining the Competitiveness of a Communications Service or Facility.

Policymakers could consider a similar statute providing for price deregulation of electric services found to be subject to effective competition. For additional flexibility, policymakers could also consider allowing partial deregulation of services by customer class and/or by region or area. Competition rarely develops uniformly across geographic regions or customer classes. As such, a flexible deregulation statute would allow the Board to deregulate as competition develops for a particular customer class or geographic area, rather than only on a service-by-service basis.

Another option being advanced is date-certain price deregulation (e.g., after the transition period). Date-certain price deregulation provides certainty and could encourage CESPs to enter Iowa's market. However, no guarantee exists that markets will truly be open at the end of the transition period and that all unreasonable and artificial barriers to entry have been removed. A final option would be to ensure no artificial barriers to entry exist and to establish specific market conditions that must be in place prior to price deregulation.

Future Provisioning of Open Access

A service should not be presumed permanently non-competitive. Technological advances can bypass traditional economies of scale. For example, development of affordable real-time telemetering for small customers could make meter and meter reading monopolies obsolete and could eliminate the need for load profiling. Similarly, future fuel cell or battery storage technologies may someday make wire-based transmission and distribution an outdated concept. Therefore, policymakers should consider authorizing procedures for evaluating whether open access for other services is warranted in the future. This would involve petitioners proposing rationales for opening other incumbent provider services to competitive access, either through rulemaking or contested proceedings, subject to Board approval.

2.3 MARKET POWER[16]

A firm or group of firms which has the ability to increase profits by setting prices above competitive levels and restricting output below competitive levels in a particular market has market power.[17] Market power abuse reduces economic efficiency and causes inefficient transfer of wealth from the consumer to the producer. Customers having the least alternatives are the most hurt by market

---

[16] Many of these introductory ideas were first discussed by staff in two earlier reports in Docket No. NOI-95-1: Iowa Utilities Board, "Regulatory and Restructuring Options in the Electric Industry (A Discussion Paper)," April, 1996, pp. 127-148; and Iowa Utilities Board, "Regulatory and Restructuring Options in the Electric Utility Industry (A Staff Analysis)," January 1997, pp. 193-223.

[17] Competitive price means the equilibrium price in a competitive market--the "marginal cost of the most costly unit necessary to satisfy industry demand." Gregory J. Werden, "Identifying Market Power in Electric Generation," Public Utilities Fortnightly, February 15, 1996, p. 16.

power abuses.

The Board's Action Plan concluded:

- Vertical market power exists when a competitor has the ability to favor its own generation due to joint control of production and transmission or joint control of production and the utility purchasing function.

- Horizontal market power exists when a competitor has the ability to influence production prices due to the concentration of generation ownership.

- Market power results in less than efficient prices because incumbent monopolies (operating within a hybrid monopoly/potentially competitive market) have incentives to:
    1) shift costs away from potentially competitive customers and services to monopoly customers and services by changing established cost-of-service principles;
    2) prohibit efficient competition (within their service territories) by pricing production services below cost in the short term; and
    3) accelerate recovery of capital assets by shortening approved depreciation lives.

- A market in which certain competitors enjoy special subsidies or tax incentives could result in less than efficient prices.

- Actions should be taken to mitigate the effects of vertical and horizontal market power and special subsidies in a transitioning competitive market.

In addition to the concerns raised in the Board's Action Plan, the exercise of vertical market power could hamper competition by limiting access to essential transmission and distribution facilities or by giving priority to affiliated generation assets in dispatch and transmission. Vertically-integrated utilities could also advantage affiliated energy service businesses through exclusive control of customer billing and usage information.[18]

Antitrust is considered inadequate to monitor and prevent market power abuses within a restructured electric industry. "While the Sherman Act makes anti-

[18] Incumbent providers have considerable information about their customers, including individual load profiles and billing histories. Unless this information is also available on a comparable basis to

competitive agreements and exclusionary conduct unlawful, a company with market power does not break the law by charging monopoly prices or limiting its output." The illegal behavior is also hard to detect and could have a deleterious impact before the judicial system can provide remedies.

Two broad policy options are available to combat market power abuses. The first option restricts the market at the outset. Advocates of this approach argue market power concerns must be addressed early and effectively, or a competitive market may never develop. The second option allows the market an opportunity to develop and solve its own problems to the extent possible. The second option suggests Board monitoring of the market and the later application of remedies if the market fails to develop adequately.

Indicative of the first option, the staff of the Virginia Commission argue "policymakers must take every precaution to anticipate and frustrate undue market power influences in advance since the potential public interest costs of policy missteps could be great."[19] The Competition Policy Institute (Institute) also found that "state regulators should deal with market power concerns at the same time restructuring plans are being developed . . . (because) it is unlikely they will have an opportunity to go back and fix structural problems at a later date."[20] Renowned economists have also argued "once the deregulation process moves toward completion, the prospects for achieving structural separation are greatly diminished."[21]

The second option, which frees markets to solve their own problems, is generally advanced by incumbent utilities favoring restructuring or by policymakers concerned with the possible consequences of mandatory

---

alternative providers, an advantage resides with the incumbent provider.

[19] Virginia PUC Staff Report, "Market Power," Ch. 3, p. 1. (http: //dit1.state.va.us/scc/news/ streprt3.htm)

[20] Ronald J. Binz and Mark W. Frankena, "Addressing Market Power: The Next Step in Electric Restructuring," Competition Policy Institute, p. 7.

[21] Harry M. Trebing, "Concentration and the Sustainability of Market Power in Public Utility Industries,"

divestiture.[22] If a unrestricted market approach is taken, policymakers should adopt various forms of behavioral and incentive mechanisms to guide the market's development, as well as requiring functional separation of competitive and regulatory services. Sufficient regulatory authority is also needed to monitor the evolving market and evoke remedies if the market fails to develop or market power abuses are found.

Whatever remedies are advanced, market power concerns must be addressed. Policymakers should avoid any "restructuring that, on net, enhances market power which . . . exceeds in 'cost' any economic benefits achieved."[23] Moreover, not addressing market power concerns could hamper restructuring. A current example is the recent shift of Michigan industrials from arguing for retail markets most of the last decade to arguing for traditional regulation, in large part because "the commission does not have the necessary means to control market power."[24] The appropriate remedies which may have prevented the Michigan example include:

- **Divestiture** - severing monopoly and competitive functions through the sale of assets to an unaffiliated entity.

- **Functional Separation** - separating monopoly and competitive functions within the same company.

- **Structural Separation** - forming separate corporate subsidiaries for monopoly and competitive functions under a holding company structure.

The Regulatory Assistance Project, March 1998, p. 4.

[22] While various well-developed theories exist regarding likely efficiencies to be gained and to be lost as the industry moves to alternative structures, "there is little quantitative evidence on the cost structure of electric utilities to guide policymakers on restructuring decisions." Lawrence J. Hill, "Economic-Efficiency Consideration in Restructuring Electric Markets," Oak Ridge National Laboratory, ORNL/CON-436, December 1996, p. xi.

[23] Louis A. Guth, "An Overview of Market Power Issues in Today's Electricity Industry," The Electricity Journal, July 1998, p. 17.

[24] "In Major Reversal, Michigan Industrials Call for Abandoning Deregulation Effort," Electric Utility Week, September 7, 1998, p. 1.

- **Prohibiting Affiliate Use of Parent Utility's Name or Logo**
- **Monitoring**
- **Mandatory Participation in an Independent System Operator**
- **Regulatory Oversight of Mergers**

These remedies are explained below.

<u>Divestiture</u>

Divestiture severs all ownership links between the regulated and unregulated functions. It is an effective tool to diminish both vertical and horizontal market power concerns. Divestiture prevents self-dealing abuses and cross-subsidization due to vertical market power and reduces the need for regulatory oversight. Horizontal market power could also be mitigated by requiring the transfer of a substantial portion of the utilities' generation assets to several smaller and unrelated companies.

While an effective market power remedy, mandatory divestiture could result in a host of financial and tax problems stemming from the terms of mortgage indenture bonds and taxation of the transaction. Utility mortgage indenture bond clauses could lead to bond redemption and refinancing. In addition, divestiture could cause significant taxable capital gains, resulting in a transfer of wealth from the state to the federal government. The economies of vertical integration are also lost with divestiture. These economies primarily result from fewer transaction costs. Customers could also lose the ability to one-stop shop for electric service.

Divestiture policy varies considerably across the states engaged in restructuring. At least two states have mandated divestiture--Maine via legislation and New Hampshire via Commission order. Other states are less certain of their authority to mandate divestiture. These states take an incentive approach to break-up vertically-integrated companies and encourage a dispersion of ownership. Most prevalent is the tying of the recovery of stranded costs to the utility's voluntary divestiture of all or a portion of its generation.[25] Other states have chosen to hold mandatory divestiture in reserve to use if other policies and tools fail to produce effective competition.[26]

Policymakers may want to reserve the right to mandate divestiture if robust competitive markets do not develop in Iowa. This approach is consistent with the philosophy of letting the markets, to the extent possible, solve their own problems. At a minimum, the Board should monitor the emergence of a competitive market and prepare a report to the legislature as to the need for divestiture.

Functional/Structural Separation[27]

In states not mandating divestiture, functional or structural separation has been proposed. By themselves, these structural changes to the incumbent utility do little to reduce market power. To counter these limitations, behavioral and accounting remedies are often adopted.[28] These remedies include standard-of-

---

[25] For example, Connecticut law does not mandate divestiture per se but will allow recovery of stranded costs only if generation is sold or at least offered at auction. In Arizona, utilities have their choice between divestiture via an auction to allow recovery of all stranded costs or an alternative PUC proceeding which may allocate stranded cost responsibilities between ratepayers and shareholders. Other major states promoting divestiture include California, New York, Pennsylvania, and Massachusetts.

[26] This includes Arkansas' PUC. "Arkansas Commission Calls for Retail Competition No Later Than January 1, 2002," Electric Utility Week, September 7, 1998, p. 9.

[27] The April 1996, Board staff "Discussion Paper," pp. 136-145, used the following terminology for possible organizational changes: (1) functional disaggregation; (2) structural disaggregation; and (3) corporate disaggregation. In this report, the following terms are used for the same concepts: (1) functional separation; (2) structural separation; and (3) divestiture.

[28] According to the Director of the Bureau of Competition at the Federal Trade Commission, a behavioral approach nevertheless may have several limitations. "First, it does not eliminate the incentive and opportunity to engage in exclusionary behavior. Rules can try to limit the opportunity, but few rules are invulnerable to evasion. Second, detection of violations can be very difficult. For example, discrimination in access could take the form of a subtle reduction in quality of service, whose effects could be difficult to identify and measure. Third, behavioral rules can require long-term monitoring of compliance, which can be a costly process." William J. Baer, "FTC Perspectives on Competition Policy

conduct rules and other regulation aimed at prohibiting cost shifting, self-dealing abuses, and discriminatory access to information, transmission, or distribution.[29] Behavioral solutions are inherently regulatory. The Board would need enhanced authority to guide market development and react when abusive practices are discovered. For example, this might include authority to: (1) suspend dividend payments to the parent holding company from the regulated subsidiary; (2) extend affiliate transaction laws and rules to any municipal or electric cooperative participating in the non-regulated generation business; and (3) require competitive bidding of the default provider. (See Section on Standard Offer Service).

Prohibiting Affiliate Use of the Parent Utility's Name or Logo

In most cases, a utility's name has gained consumer recognition and trust in the regulated market. Extending that name recognition into an affiliate's unregulated market raises two concerns. First, value gained at the expense of regulated service customers will yield benefits in the unregulated market. Second, use of the utility's name will give it an unfair advantage in competitive markets that otherwise equally efficient competitors cannot match. Remedial proposals include prohibition of use of the name, payments to the utility for the use of the name, or restricting use of the corporate name to tag lines.

In comments to the Public Utilities Commission of Texas[30] (PUCT), the staff of the Bureau of Economics of the Federal Trade Commission (FTC) stated that when unregulated affiliates are allowed to use a regulated parent utility's name or logo, the parent utility may have incentives to over-invest in building its

---

and Enforcement Initiatives in Electric Power," December 4, 1997, p. 7. (http://www.ftc.gov/speeches/other/elec1204.htm)

[29] A related question exists as to whether the incumbent provider's reputation and name should be available for use by the utility affiliate or whether safeguards against this usage are needed.

[30] Filed in PUCT Project Number 17549, June 19, 1998. The relevant portion of the rulemaking was withdrawn September 9, 1998.

reputation (as a provider of high-quality services, for example) in ways that are difficult for regulators to detect and prevent. This may result in harm both to competition, because the affiliate does not have to expend resources to build its reputation, and to consumers, because these expenditures inflate the utility's rate base. Accordingly, the FTC advised the PUCT to investigate the likely effects on consumers of the use of a utility's name and logos by unregulated affiliates.

The FTC staff went on to explain that an "unregulated affiliate's use of its regulated parent utility's name or logo is a particularly difficult form of cross-subsidization to police. This concern is most likely warranted if three conditions are present. First, the reputation of the regulated parent utility must be effectively embodied or represented by its name or logo. Second, the regulated parent utility must be able to improve its reputation by investing in equipment (or human capital), and these investments must be of the type that regulators would traditionally include in the rate base of the regulated utility. Third, the unregulated affiliate must be able to enhance its own reputation among consumers by using the name or logo of the regulated parent utility, even if elements of the regulated parent's reputation do not apply to the affiliate."

The FTC staff pointed out another potential harm. Consumers might be confused or deceived if elements of the reputation of the regulated parent utility are not applicable to the unregulated affiliate. The FTC staff suggests regulators evaluate this issue by focusing on the impression that consumers are likely to have under a particular policy alternative, and whether that impression would be accurate.

The Georgia Public Service Commission recently considered Atlanta Gas Light

Company's use of the name Atlanta Gas Light Services, Inc. for the name of its affiliated marketer.[31] Atlanta Gas argued that enhancing the knowledge of the consumer was the reason for giving the marketer a name easily identified with its utility parent. The name gives the consuming public more information about the marketer by identifying the firm the customer will be dealing with. Atlanta Gas pointed out that competing marketers are free to use corporate names such as Shell and Fina that are recognized by the consuming public and are associated with nationwide oil, gas, and energy providers. Thus, according to the utility, use of the "Atlanta Gas Light" name was only a way of equalizing the competition for the natural gas market in Georgia. Atlanta Gas also argued the goodwill of the utility's name belonged to the shareholders, especially when advertising expenses had often been disallowed in rate cases.

The Georgia PSC rejected the marketer's use of the utility name prior to the maturation of competition. It did allow the marketer to use a tag line that discloses the corporate relationship, but the tag line was required to include a statement that no preferential treatment by the utility would accrue to customers who chose to deal with the affiliated marketer. The marketer ultimately selected a name unrelated to the parent utility.

Monitoring

Staff's earlier analysis of the regional markets using the Herfindahl-Hirschmann Index (HHI) found market power problems were possible, especially during conditions of transmission constraints.[32] However, the market power issue can not be fully resolved in advance of restructuring, nor is a single market power determination adequate. The full scope of this issue will evolve as the market

[31] In re Complaint of PanCanadian Energy Services Inc., et al. v. Atlanta Gas Light Company and Atlanta Gas Light Services, Inc., Georgia PSC Docket No. 9156-U, July 16, 1998.

[32] Iowa Utilities Board, op. cit., January 1997, p. 208.

evolves. Monitoring of the market must, therefore, continue. In addition, "(b)oth the dynamics of industry change and the advancement of economic theory anticipate further changes in market-power measurement methodology."[33] These dynamics can be seen in the rapid pace of mergers (e.g., the recent proposed purchase of MidAmerican Energy Company by CalEnergy) and unexpected market developments (e.g., the wholesale price spikes of last June).[34]

The recent market spikes demonstrate an important characteristic of a competitive electricity market. Electricity cannot be stored economically and is difficult to transmit over long distances. Demand and supply conditions can change every hour of the year, in a sense producing 8,760 different markets. While traditional concentration analysis[35] may be helpful in judging the potential market power of a particular market, it is not adequate to forecast what might happen during peak demand periods, especially if transmission or suppliers falter. "(D)uring peak demand conditions when the weather is most extreme and electricity is most essential in the context of public health and welfare, the potential for market power abuse may be the greatest."[36] There is a need to develop and use regional simulation models using transmission capacity and costs, generation capacities and costs, and the energy demands for the different areas to help forecast the potential for these abuses.

To the extent policymakers rely upon competition, it is important to take seriously the goal of "ensuring that consumer interests are protected and that the process

---

[33] Walter Surrat, "The Analytical Approach to Measuring Horizontal Market Power in the Electric Utility Markets: A Historical Perspective," The Electricity Journal, July 1998, p. 23.
[34] Unusual price volatility was experienced in the Midwest during the week of June 22nd. This was the result of an already tight capacity situation, tested by both hot and severe weather, and then "exacerbated by defaults on contracts by some market participants." Paul D. McCoy, of Commonwealth Edison Company, "Federal Energy Regulatory Commission Meeting on Midwest Electric Pricing Issues," August 14, 1998, p. 1.
[35] Beyond just identifying a dominant firm, there are two traditional measures of market power. One is the four-firm concentration ratio which simply adds the market shares of the four largest firms. Another is the Herfindahl-Hirschmann Index (HHI) which measures concentration by summing the squares of market shares for all firms in that market.
[36] Virginia PUC Staff Report, op. cit., p. 2.

of competition is allowed to work unfettered and undamaged."[37] If Iowa's policymakers choose to allow unrestricted competition in generation during the transition period, a monitoring role for the Board is essential. It is by no means certain that CESPs would enter the market in adequate numbers to limit the utilities' market power, especially in the residential and small commercial markets. Transition monitoring may evoke Board remedies during the transition period plus lead to a end-of-transition report to the legislature about the need for additional legislative remedies.

Independent System Operator (ISO)

The Board, in a July 1998 order adopting ISO principles, stated: "The purpose of an ISO is to provide reasonable and equitable access to the transmission system, to operate the transmission system safely and reliably, and to prevent the transmission system from becoming a factor in enhancing market power in a competitive electric market." Electric competition will only exist when paths of electricity from the point of generation to the point of use are available to all buyers and sellers. These paths to transport electricity are called transmission lines. If vertically-integrated utilities continue to own and control both generation and transmission lines, they may use their control of critical transmission facilities to favor their own generation over their competitor's generation. The Energy Policy Act of 1992 (EPACT) mandated open access to transmission. FERC Orders 888 and 888A, implementing the EPACT, urged the establishment of independent transmission operators to make transmission available on a comparable and nondiscriminatory basis to all users of the transmission system. These transmission operators are commonly known as Independent System Operators or ISOs.

[37] Ibid., p. 31.

Legislative and regulatory initiatives at both the state and federal levels are encouraging ISO formation. Discussions on forming ISOs are being held nationwide. These include INDEGO in the pacific northwest, Desert STAR in the southwest, the Midwest and MAPP ISOs in the midwest, and Southwest Power Pool in the southwest. The FERC has approved ISOs for California, New York, the Pennsylvania-New Jersey-Maryland Power Pool, the New England Power Pool, and the Midwest ISO. The FERC is actively seeking legislative authority to require the formation of ISOs.

Although the idea of an ISO to address market power over the transmission system enjoys widespread support, regulatory involvement may be necessary in forming ISO policies and procedures. It is important for ISOs to reflect special needs of the region. Different regions have different transmission development histories. Transmission design and operation also differ from one region to another. “Cookie-cutter” ISO policies cannot be imposed on all transmission systems and/or regions. The Board needs to oversee ISO formations in Iowa to ensure that solutions that worked well in other regions/states are not infeasible or counterproductive for Iowa’s electric transmission system. Board oversight is also needed to ensure the ISO does not favor one specific interest over another and maximizes the benefits of the available transmission for all, while ensuring the reliability of the system. The Board’s ISO principles provide a good basis for Iowa’s utilities to evaluate ISO membership.

Although some Iowa utilities have expressed interest in joining either the Midwest or MAPP ISO, others have been reluctant to turn over control of their lines to an ISO. There have also been extensive discussions on whether participation in an ISO should be voluntary or mandatory. If the Board sees that control of the transmission system is becoming a factor in enhancing market power in Iowa’s retail electric market, it may require authority to mandate ISO participation.

Unfortunately, mandating ISO participation will not solve market power concerns if a "workable" ISO is not available. The industry is now proceeding voluntarily to design and form workable ISOs in the midwest. These voluntary efforts may not produce an ISO that complies with the Board's principles. In addition, since many of the transmission facilities in Iowa are jointly owned, it is imperative Iowa's transmission owning utilities join the same ISO. The Board and its staff should continue to work with regional reliability organizations, FERC, and other state regulatory agencies within the region to encourage development of an ISO consistent with the Board's principles.

Merger Policy

Substantial merger activity has occurred in the midwest over the last few years. In Iowa alone, the number of separate electric investor-owned utilities has dropped from seven to two since 1990. If left unchecked, it is possible a tight oligopoly (in which just a few firms control most of the generating capacity in the region) will evolve.[38] An oligopoly market structure would lead to undue exercise of horizontal market power.[39] This can result in the creation or maintenance of entry barriers for new competitors.

The high degree of merger activity in the electric industry led the FERC to update its merger review policy. The FERC's "December 1996 Merger Policy Statement" set out a detailed screening process based upon the FTC/DOJ Guidelines.[40] Under this policy, the FERC has conditioned merger approvals by imposing market power mitigation requirements.[41]

---

[38] The owner of a diversified set of generating units would likely have access to cheaper financing for its projects than would the riskier new entrants into the market.
[39] An excellent example of undue horizontal market power is the British experience of electric power deregulation. Its privatization of its state-owned industry essentially produced a duopoly of two generation firms--which produced higher prices, price volatility, and additional risks to suppliers and customers. Ultimately, regulation in the form of price ceilings was reimposed.
[40] These were discussed on pages 201-203 of the Board Staff's January 1997 "Staff Analysis."
[41] Another constraint upon the accumulation of market power by utilities is the FERC's authority to grant

State regulators have also sought to limit market power through merger review. Iowa's authority to review and/or condition mergers is limited compared to many other states. If merger review is to be used as an effective tool to limit horizontal market power, the Board may require additional authority to condition mergers and acquisitions as well as lengthening the time for review. To judge the market power implications of proposed mergers, it is necessary to use traditional market power analysis tools, as well as models that simulate transmission and generation operations in a region.

2.4 AFFILIATE TRANSACTIONS

Efficient competition is fostered by encouraging participation by many qualified entities. This includes unregulated affiliates of utilities. These affiliates may offer other regulated services, provide electric service in other geographic areas, conduct businesses closely related to the utility functions, or conduct business removed from the electric industry.

Affiliate activities may be conducted by the utility itself or may be offered by separate corporations that are subsidiaries of the utility or subsidiaries of the utility's parent corporation. Regardless of the business relationship between the affiliate and the electric supply service, the capital and credit of the utility are fully intertwined with the other business.

Because of the inherent incentives for utilities to favor affiliates and to subsidize competitive activity from the regulated business, transactions between utilities and their affiliates invite a high level of regulatory scrutiny. Regulators have traditionally been concerned that corporate diversification into non-utility lines

---

or deny market participants' applications to charge market-based rates. Under those proceedings, applicants must show that they either do not have market power in the relevant market or that it is could: 1) financially compromise the regulated entity; 2) require customers of the regulated entity to subsidize competitive ventures; and 3) advantage the incumbent company's competitive affiliate. Restructuring requires closer scrutiny of affiliate transactions, because competitive profit opportunities are enhanced. In addition, vertically-integrated utilities, which offer essential delivery functions (i.e., transmission and distribution) to competitors, must be closely monitored to guard against cost shifting between regulated and non-regulated affiliates and discriminatory access practices.

A white paper prepared for the National Association of Regulatory Utility Commissioners (NARUC) Committee on Electricity in 1997 offered the following provisions to prevent cost shifting between regulated and non-regulated affiliates:[42]

- Federal Access to Books and Records
- State Access to Books and Records and Personnel Capable of Responding to Inquiry from Regulators
- "Ordinary Course of Business" Contracts
- Separation Plans or Operating Agreements
- Allocation of Costs
- Audit Authority for State Commissions

The white paper also suggested the following tools to avoid subsidized or predatory pricing in unregulated markets:

- Code of Conduct filed with State and Federal Commissions
- Documentation of Compliance with the Code of Conduct
- Minimum Code of Conduct Requirements for Affiliates (including Service Companies)
- Minimum Code of Conduct Requirements for Utilities

In pursuing goals of consumer protection and preventing anti-competitive behavior in a restructured industry, regulators need the ability to use both structural and behavioral remedies. Structural remedies deal with corporate

---

mitigated.

organization. These remedies directly alter incentives and may limit the range of business activities corporations may engage in. Structural remedies are discussed in the Market Power Section of this report. Behavioral remedies set continuing standards to offset incentives for discriminatory or anti-competitive behavior. Behavioral remedies usually must be monitored on a continuing basis. The following behavioral mechanisms for oversight and policing of affiliate transactions in a restructured industry are addressed in this report:

- Codes of Conduct
- Accounting and Auditing
- Cost Allocation Principles and Manuals
- Cost Treatment

Codes of Conduct

In the past, vertical integration of the electric industry has facilitated regulatory oversight. Once a firm was labeled as a public utility, regulators could review all its activities. A contrasting approach is to regulate a set of activities, regardless of what firm performs them. Regulation oriented around conduct is less likely to deter entrants than regulation oriented around utility status.

The distinction between status and conduct regulation gains importance in a competitive structure. Status regulation will tend to draw all activities of a firm into regulatory control, even activities that may be well outside the scope of the utility service. Regulation based on conduct will tend to ignore these outside activities unless they impinge on the regulated activity in some way. A shift to a more competitive industry structure suggests a regulatory shift from status to conduct.

[42] The full text of this white paper is found in Appendix C.

One approach which shifts the focus away from status to conduct is the establishment and enforcement of codes of conduct for affiliate transactions. Codes of conduct provide varying degrees of detail in outlining permissible and impermissible relationships between utilities and affiliates. Their essence is to require that affiliates be treated at arms' length in dealings with the utility.

The white paper prepared for the NARUC Committee on Electricity defines the following minimum requirements for an affiliate code of conduct (including service companies):

- affiliate shall operate independently from the utility company;
- affiliate shall maintain books, records, and accounts in the manner prescribed by the appropriate Federal and State Commissions which shall be separate from the books, records, and accounts maintained by the utility company;
- affiliate shall have separate officers, directors, and employees from the utility company;
- affiliate may not obtain credit under any arrangement that would permit a creditor, upon default, to have recourse to the assets of the utility company; and
- affiliate shall conduct all transactions with the utility company on an arm's length basis with any such transactions reduced to writing and available for public inspection.

Minimum code of conduct requirements for utilities include:

- utility may not discriminate between an affiliate and any other entity in the provision or procurement of goods, services, facilities, and information or in the establishment of standards;
- utility shall account for all transactions with an affiliate in accordance with generally accepted accounting principles or accounting principles approved by the appropriate Federal and State Commissions; and
- utility shall not carry out any promotion, marketing, sales, advertising, or research and development for or in conjunction with an affiliate.

Accounting and Auditing

The primary tools traditionally available to regulators to detect inappropriate costs were those of accounting and auditing. The question is whether these tools are inadequate in a more competitive market. The effectiveness of the tools depends on the ability of regulators to gain access to the accounts that might show affiliated transactions and the ease with which those transactions can be identified. Access to books and records is essential to the audit function.

IOWA CODE § 476.71 through 476.75 provide a strong framework for identifying, reporting, and auditing transactions between utilities and affiliates. To be applicable in a restructured environment, these provisions would require some adjustments and definitional changes. Most importantly, a new remedial focus is needed to replace the current focus on ratemaking.

Audit requirements: Guidelines for Cost Allocations and Affiliate Transactions (Guidelines), developed by the NARUC Staff Subcommittee on Accounts with significant input from electric utilities and other industry parties and regulatory agencies, suggest minimum requirements for records of transactions between utilities and affiliates, such as:

- An audit trail shall exist with respect to all transactions between the regulated entity and its affiliates that relate to jurisdictional services and products.

- Each regulated entity's cost allocation documentation shall be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request. Further, any jurisdictional regulatory authority may request an independent attestation engagement of the Cost Allocation Manual (CAM).

- The cost of any independent attestation engagement, associated with the CAM, shall be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

Requirements for Separate Subsidiaries: Regulators face a dilemma in structuring corporate affiliates. Requiring separate subsidiaries for non-regulated activities usually facilitates isolating affiliate transactions. Regulators have less need to review utility books and records when separate subsidiaries are used. It is sometimes more difficult, however, to gain access to records of subsidiaries and holding companies that may be maintained away from the utility offices and perhaps outside the state.

Single corporations that mix utility and non-utility functions present the other side of the dilemma. While all relevant costs are shown on the records, more complex accounting separations are needed to divide costs between the functions. Utilicorp United, Inc. is an example of a utility that operates multiple functions in multiple jurisdictions through a single corporation.

In either system, any mixed use of personnel or equipment may require stringent record keeping to account for people's time, vehicle use, computer time, and so forth. In addition, as competition becomes a factor, there is regulatory concern that competition not be influenced by corporate affiliation. Therefore, access to information, plans, and funds may be just as undesirable as possible cost preferences. In restructuring the natural gas pipeline industry, the FERC adopted strong requirements that the gas merchant business be separated both physically and structurally from the transportation function of the pipeline. Offices were relocated and common computer systems were separated. A more competitive electric industry may have to deal with similar kinds of requirements.

Cost Allocation Principles and Manuals

If permitted by a code of conduct, utilities and affiliates may conduct functions jointly in order to gain the economies of shared costs. The Guidelines suggest the following techniques for assigning costs among the corporate affiliates using joint and shared functions:

- To the maximum extent practicable, in consideration of cost benefit standards, costs should be collected and classified on a direct basis for each service or product provided.

- The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities can consider incremental, market-driven, negotiated pricing or other methods for allocating costs, and pricing transactions among affiliates.

- To the extent possible, all direct and allocated costs between regulated and non-regulated products and services shall be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation shall be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

- The allocation methods shall apply to the regulated entity's affiliates in order to prevent cross-subsidization from, and ensure equitable cost sharing between, the regulated entity and its affiliates, and vice versa.

- All costs shall be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

- The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, shall be identified and used to allocate the cost between regulated and non-regulated services or products.

- The overhead costs of each business unit, including the allocated costs of shared services shall be spread to the services or products to which they relate using relevant cost allocators.

Regulatory agencies, including the Board, have often found it helpful to review or approve the actual instructions used by utility accounting personnel through the filing and approval of CAMs. The Guidelines are found in Appendix D.

Cost Treatment

As explained earlier, a principal regulatory objective in setting cost-based rates is to prevent overcharges to utility customers. Other objectives may be to prevent excessive profits through exploitation of a franchised monopoly and to prevent under-pricing of the affiliate's services through subsidies made possible by the utility.

Transactions between a utility and its affiliates warrant a higher level of scrutiny than arms-length transactions. Prices set in an open market or through competitive bids are not usually challenged; the market process validates the reasonableness of the price. Transactions with affiliates should be validated by regulators. The following options are available:

- Prior Approval or Post-Approval
- Transfer Pricing
- Royalty Payments
- Price Caps
- Differential Rates of Return

These options are discussed below.

Prior Approval or Post-Approval - Regulators can review affiliate transactions before they occur through a pre-approval process or after they occur either through a reporting process or in ordinary rate case review. They may be able to waive review of de minimis or routine transactions. Alternatively, some commissions accept costs absent a challenge.

Transfer Pricing - Economists use the term “transfer pricing” to refer to the prices for goods or services transferred between affiliates. A typical rule to avoid abusive affiliate transactions is to value the transaction at market value or book value, whichever is more favorable to customers. Stated more completely, if the utility is selling or transferring to an affiliate, it should receive the higher of book or market value for assets or for the use of facilities or personnel. Regulated electric services should be sold to an affiliate at tariffed rates. If the utility is buying goods, services, or assets, it should pay the lower of book or market cost. Market cost should be tested, where practical, by open competitive bidding. The utility's need for the service or asset should also be assured. These rules are generally applicable to all transfers, whether they are real estate, financial instruments, emissions allowances, labor, services, or use of equipment. Application of the rule is more of an art than science.

Royalty Payments - A different technique recognizes the burden and difficulty of making precise market/book determinations on what may be a large number of transactions. A short-cut answer is to require the affiliate to pay a fixed charge to the utility as a royalty for the unquantifiable benefits of its association. Setting this charge at a practical level is a matter of judgment. Reasonable compensation to ratepayers is the objective. The royalty amount should not be so high as to hinder the success of the affiliate, nor so low as to give it an unfair advantage in a competitive market.

Price Caps - Price-cap regulation has been adopted by some states for telephone regulation and may be extended to electric utility regulation. The essential feature of price regulation is to allow prices to be adjusted periodically from starting levels. The adjustments are limited by a formula that includes inflation, a productivity factor, and allowance for tax changes or other exogenous factors. Because rate levels are not tied to earnings or cost, regulatory concerns over affiliate transactions are greatly diminished. Where regulators are required by statute to avoid unfair competition through cross-subsidy, there is still a need to be attentive to affiliate issues.

Differential Rates of Return - Regulators may at times find it necessary to differentiate the capitalization and earning levels of the utility from some or all of its affiliates. Differential rates of return can be calculated and allowed based on specific debt or preferred financing and their cost; equity earning levels specific to the different enterprises and their risks; and the debt-equity ratios appropriate to each venture. These techniques, if properly used, can be used to set utility rates with appropriate return components.

2.5 GENERATION AND TRANSMISSION SITING

The Board's role in granting certificates for new generation plant and franchises for new transmission lines could change in a restructured industry. This section looks at both generation and transmission siting.

Generation

IOWA CODE § 476A sets forth procedures and criteria for determining whether proposed generation plants are in the public interest.[43] The Board makes this determination in contested proceedings with input from other regulatory agencies. Board rules for conducting the proceedings are set forth in IOWA ADMIN. CODE § 199-24.

The Board makes its certification decisions according to criteria listed in IOWA CODE § 476A.6. The criteria in IOWA CODE § 476A.6(1) through (3) are applicable to all entities, both utility and non-utility, and are intended to ensure new plants conform with environmental and land use standards administered by state and local regulatory agencies. Specifically, these criteria are:

1. The services and operations resulting from the construction of the facility are required by the present or future public convenience, use, and

[43] IOWA CODE § 476A applies to plants sized 25 MW or larger. However, IOWA CODE § 476A.15 allows the Board to waive certification requirements for plants sized 100 MW or smaller. Thus, certification is mandatory for plants larger than 100 MW, discretionary for 25 MW to 100 MW plants, and not required for plants smaller than 25 MW.

necessity.

2. The applicant is willing to perform such services and construct, maintain, and operate the facility pursuant to the provisions of the certificate and this chapter.

3. The construction, maintenance, and operation of the facility will cause minimum adverse land use, environmental, and aesthetic impact and are consonant with reasonable utilization of air, land, and water resources for beneficial purposes considering available technology and the economics of available alternatives.

IOWA CODE § 476A.5 prohibits the Board from granting certificates for plants that do not comply with the permit and licensing requirements of other state regulatory agencies.[44]

The criteria listed in IOWA CODE § 476A.6(4) through (6) are applicable only to utilities. These criteria are designed to ensure utilities use least-cost resource planning in determining their generation plant needs.[45] In a competitive retail generation market, policymakers may want to consider wholly or partially exempting utility plants from Iowa least-cost planning criteria.[46] Such criteria might be regarded as irrelevant or unfairly burdensome for incumbent providers that compete with non-utility plants.

However, environmental and land use criteria should continue to be relevant for

[44] However, this does not prohibit the Board from granting certificates for plants that conflict with local zoning requirements.

[45] A 1997 Wisconsin law similarly distinguishes between utility and non-utility plants in certification proceedings, exempting the non-utility (i.e., merchant) plants from complying with Wisconsin's least-cost planning criteria. The Wisconsin law defines merchant plants as not providing service to any Wisconsin retail customer. They only sell into competitive wholesale and out-of-state retail markets. Wisconsin utilities or their affiliates cannot own, control, or operate merchant plants without approval from the Wisconsin Public Service Commission. Approval is granted only if: (a) the utility either divests its transmission or transfers transmission control to an independent system operator; and (b) the Commission finds there will be no anti-competitive impact on electricity markets or on any retail customer class.

[46] Another option is suspending the criteria during a competitive transition period.

all entities, both utility and non-utility. Board plant certification proceedings could continue serving a useful role by providing a centralized administrative forum for ensuring compliance with land use and environmental standards administered by other state agencies.[47] Alternatively, such a forum could be transferred and administered by an agency with more direct regulatory involvement, such as the agency that enforces state environmental standards.

Transmission

The Board grants franchises for new transmission lines under IOWA CODE § 478. In contested proceedings, the Board determines whether the public interest is served by mandating new transmission line easements across landowners' property. Board rules for conducting the proceedings are set forth in IOWA ADMIN. CODE § 199-11. Board transmission franchise proceedings will continue to serve a useful role in balancing private land use interests with the public's need for new transmission paths.

[47] Under the previously-cited Wisconsin Law, the Wisconsin Public Service Commission's certification proceedings continue to fill this role for both utility and non-utility (i.e., merchant) plants.

3.0 TRANSITION ISSUES

In reaching the desired end-state, several transition issues need to be addressed. This report addresses the following transition issues:

- **Standard Offer Service** - Should a bundled regulated service be available to customers during the transition period?
- **Default Provider -** Should the default provider be determined through competitive bidding?
- **Phase-In Versus Flash-Cut** - Should open access be phased-in over time or made available to everyone at the same time (i.e., flash-cut)?
- **Reciprocity** - Should utility participation in another utility's open retail market require the utility to open its own service territory in a reciprocal manner?
- **Unbundling** - Should existing utility rates be unbundled into separate components for generation, transmission, distribution, and customer service?
- **Contracts** - How should existing contracts for customer load be addressed?

3.1 STANDARD OFFER SERVICE

For customers choosing not to choose a competitive electric service provider or who do not attract alternative providers, most states have instituted what has commonly been referred to as standard offer service during the transition period. Standard offer service is traditional regulated "bundled" service that electric utilities have historically provided their customers. Under standard offer service, the customer would see virtually no change in their electric service.

Three questions need to be addressed regarding standard offer service:

- Who should provide standard offer service?
- How should standard offer service be priced?

- What customers are eligible for standard offer service?

Provider of Standard Offer Service

The provider of standard offer service is referred to as the default provider. The default provider can be determined through competitive bidding or designation. The incumbent provider is commonly designated the default provider.

Bidding out the default provider is one mechanism being proposed to overcome the unique barrier to entry referred to as customer inertia. Customer inertia is manifested in markets previously served by a monopoly provider. Without some means of jump-starting competition, customer inertia could maintain monopoly market shares for several years.[48] The Ohio Commission staff has proposed bidding out the default provider in “retail marketing areas” designed to provide competitive rates for retail customers who do not elect a CESP. Retail marketing areas (RMAs) are geographic designations for the purpose of aggregating retail electric service customers. Customers who do not like the default provider selected for them may switch by paying administrative costs. A rate cap is in effect during the transition period based on current rates. If no one bids at the capped rate, the incumbent provider provides service at capped rates.

A potential problem with bidding out the default provider is forcing customers to change to a provider they did not choose. Some stakeholders have referred to this practice as government-mandated slamming. The residential/small commercial customer survey conducted by the Social Science Institute of the University of Iowa on behalf of the Board and Energy Center indicates customers are satisfied with their current electricity service.[49] Iowa’s consumers may not choose an alternative provider because they are content to remain with

---

[48] It took 12 years for AT&T’s market share to fall below 50 percent in the long-distance telephone market.

[49] The University of Iowa survey report has not been finalized as of the printing of this report.

their incumbent provider.

Another problem stems from Iowa's relatively low electricity prices in the region. If prices are capped at current embedded generation rates, alternative providers may not bid into Iowa's market. Bidding at market (i.e., absent the cap) could result in higher prices for consumers and increased profits for Iowa's incumbent providers. Capping prices during the transition period is one way to share potential transition benefits with customers.

In most states, the default provider is the incumbent provider. Designating the incumbent provider as the default provider during the transition period results in the least disruption for customers. If a competitive market does not emerge during the transition period, the Board may want to consider mandating competitive bidding for the default provider after the transition. New legislative authority would be needed to exercise this option.

Pricing of Standard Offer Service

If the incumbent provider is the default provider, generation would have to be procured either through the incumbent provider or by CESPs in the open market. Some states require the generation component of standard offer service to be bid out to the open market. By charging customers the market price for generation, customers indirectly participate in the competitive market. However, states proposing this option generally have high electricity rates. In these states, customers would likely benefit by paying a market price lower than the incumbent provider's tariffed rates. Iowa's tariffed rates are low in comparison to its market region. Therefore, pricing generation at market could result in higher rates than traditional cost-based rates.

Several states have instituted standard offer service in conjunction with price caps or reductions. The Transition Cost/Benefit Team Report recommends a price cap for standard offer service as a mechanism for sharing transition benefits, if these benefits materialize. Some states have reduced rates for specific utilities, prior to restructuring, as part of their transition into a competitive market. Arbitrary rate reductions in Iowa would make it more difficult for CESPs to effectively compete in Iowa's market. In addition, Iowa's incumbent providers have reduced rates in the last few years as the result of Board-approved settlement agreements (MidAmerican Alternative Pricing Proposal Settlement - Docket No. APP-96-1) and rate reduction proceedings (IES Utilities' Rate Case - Docket No. RPU-94-2). If standard offer service is required during the transition period, it could be capped at current tariffed rates unless the incumbent provider files for a rate increase with the Board. Rates could be adjusted to reflect any exogenous events the Board deems outside the control of the incumbent provider.

Eligibility

Standard offer service could apply to all customer classes or only to those classes which may have limited market choices. The significant purchasing power of large commercial and industrial customers advantage these classes in a market environment. If lower market prices are available to these customers, standard offer service is unnecessary both during and after the transition period.

Many states take the position that once customers leave standard offer service to purchase power from an CESP, the incumbent provider is no longer required to serve them. Massachusetts is an exception and allows customers to leave and return to standard offer service as many times as they choose. Iowa customers are inexperienced in dealing with alternative providers. Therefore, it may be appropriate to allow one opportunity for the customer to return to standard offer service without penalty. After returning once, incumbent providers could then be allowed to charge customers a cost-based re-entry fee.

3.2 PHASE-IN VERSUS FLASH-CUT

Introduction of electric competition will require a decision about whether it should be phased-in or made available to everyone at the same time (flash-cut). A review of other state practices shows no clear preference for one approach over the other. Federal legislative proposals typically specify a flash-cut approach.

In discussing the feasibility of pilot programs with Iowa's utilities, it becomes clear that some time is required to adapt utility customer information and billing systems to accommodate the practice of direct access, regardless of the percentage of customers initially involved. Thus, the key does not seem to be the choice between phase-in or flash-cut but the timing involved. If the start-date is far enough in the future, both approaches provide for the necessary adaptation of utility and regulatory systems.

A potential problem with phase-in approaches is determining what customers receive choice first. This is particularly true for large industrial customers which have already been solicited by CESPs. Phasing-in a percentage of load rather than a percentage of customers would solve this problem. In other words, a certain percentage of each large customer's load would be eligible for choice in each phase. This solution would not be practical for small customers which will likely require aggregation to effectively compete in the market. If a phase-in approach is selected, each customer class should have the opportunity to participate in the market during each phase. Limiting access to large customers during the initial phases of restructuring, as was done in Michigan, precludes small customers from benefiting from any excess capacity in the region.

In addition to providing all customers access to the market at the same time, the flash-cut approach also avoids potential customer confusion over who is and who is not able to participate in the competitive market. This approach also provides a clearer and quicker indication of whether or not effective competition is developing, because the potential market is larger from the onset of open access. A smaller phased-in market may give CESPs less incentive to enter the Iowa market, which may obscure other potential barriers to effective competition. In such a case, a 5-year transition period may not be sufficient time to assess the development of competition. Finally, reciprocal opening of utility service territories (see Reciprocity Section below) may be complicated by a phase-in versus flash-cut approach.

Whether competition is introduced by flash-cut or phase-in, policymakers should recognize that utility preparations and readiness for open access are not equal. Some Iowa utilities may be prepared to offer open access on their delivery systems next year, while others may require two to three years to adapt their systems. To ensure a smooth transition, start-date selection should take into account these differences.

3.3 RECIPROCITY

Reciprocity requires utilities wanting to compete in another utility's retail market to open their retail service territories to competition in a similar manner. Some argue reciprocity ensures equal and mutual access to competitive markets, both utility-to-utility and state-to-state. Without reciprocity, a utility closed to competition could profitably sell excess generation into an open utility's retail market without risk of losing its own market. Increased stranded cost exposure could result.

Alternatively, Iowa's consumers could benefit from having no reciprocity requirement through the infusion of low-cost power from surrounding states which have not restructured (i.e., Minnesota, North Dakota, South Dakota, Nebraska, Wisconsin, and Missouri). The only state in Iowa's region which has restructured is Illinois.

Illinois's electricity rates are some of the highest in the region. A reciprocity requirement would limit Iowa's trading partner to the highest cost state in the region.

Some states provide for reciprocity in their electric restructuring laws, and reciprocity is mentioned in most federal legislative proposals. Some observers note that reciprocity provisions ultimately require states to make judgments about the openness of other states' utility markets, which may lead to federal litigation from the excluded utility or state. If a reciprocity requirement is desirable, the solution may be for policymakers to frame reciprocity as a condition utilities are allowed to impose for opening their exclusive service territories to other utilities or their affiliates.

In-state reciprocity may require amendment to IOWA CODE § 476.1A and 476.1B to allow for Board oversight of rate unbundling for electric cooperatives and municipal utilities (see Rate Unbundling Section below). Board oversight would ensure that electric cooperatives and municipal utilities do not block access to their retail markets through unreasonably high distribution rates. Board oversight could range from rate regulation to resolving discrimination disputes. For electric cooperatives and municipal utilities not wanting state oversight of distribution rates, opt-out provisions have been instituted in several state restructuring laws. Opt-out provisions allow electric cooperatives and/or municipal utilities to exempt themselves from open access requirements.

3.4 RATE UNBUNDLING

To facilitate competitive pricing, rate unbundling would break out current rate structures into functional components representing generation, transmission, distribution, and customer service. Rate unbundling allows for competitive pricing of the generation component. Customers would be able to compare the generation component of their current rate with offers from CESPs. Customers could then choose between the price offered by the CESP or standard offer service from their incumbent provider. Basing unbundled rates on existing rate structures minimizes customer confusion and prevents cost shifting among rate groups by maintaining average class pricing.

Unbundling is essential to customer choice. In anti-trust regulation, the concept of "tying" describes a situation in which a firm uses its market power in service A to improve sales of competitive service B. Tying competitive generation services to monopoly transmission and distribution services advantages the vertically-integrated electric utility. Subsidizing competitive services (e.g., generation) through pricing of monopoly services (e.g., transmission/distribution) also advantages the incumbent provider. Board ratemaking authority could be expanded to ensure comparable and nondiscriminatory access to customers through just and reasonable unbundled rates.

Current Iowa statute (IOWA CODE § 476) grants the Board broad authority for setting just and reasonable rates which could be applied to rate unbundling. IOWA CODE § 476 defines the Board's ratemaking authority as follows:

⇒ IOWA CODE § 476.2(1) (1997) Board Powers and Rules, states: The board shall have broad general powers to effect the purposes of this chapter notwithstanding the fact that certain specific powers are hereinafter set forth.

⇒ IOWA CODE § 476.4 (1997) Tariffs Filed, states: Every public utility shall file with the board tariffs showing the rates and charges for its public utility services . . . . These filings shall be made under such rules as the board may prescribe within such time and in such form as the board may designate.

⇒ IOWA CODE § 476.7 (1997) Application by Utility for Review, states: If there shall be filed with the board by any public utility an application requesting the board to determine the reasonableness of the utility's rates, charges, schedules, service, or regulations, the board shall promptly initiate a formal proceeding. Such a formal proceeding may be initiated at any time by the board on its own motion.

⇒ IOWA CODE § 476.3(1) (1997) Complaints--Investigation—Refunds, states: [T]he board, after hearing held after reasonable notice, . . . shall determine just, reasonable, and nondiscriminatory rates, charges, schedules, service, or regulations to be observed and enforced.

Board rules set forth guidelines for designing just and reasonable electric rates (IOWA ADMIN. CODE § 199-20.10). The Board could expand these rules to include principles for rate unbundling under existing statutory authority. Utility rates could then be unbundled through contested proceedings before the Board, based on application of its rules.

Electric cooperatives and municipal utilities are currently exempt from rate regulation under IOWA CODE § 476.1A and IOWA CODE § 476.1B, respectively. If policymakers require Board review of electric cooperative and municipal utility rate unbundling (see Reciprocity Section above), these statutes should be amended accordingly.

Unbundled transmission rates would require approval from the Federal Energy Regulatory Commission (FERC). In MidAmerican Energy's retail access pilot programs, MidAmerican sells unbundled transmission service to CESPs rather than individual customers, priced according to MidAmerican's FERC-approved open access transmission tariff (OATT).[50] CESPs then resell the transmission to pilot participants, along with competitive generation. The purpose of this arrangement was to simplify the transmission rate unbundling process and gain expedited FERC

[50] See Appendix A.

approval for use in small, short-duration pilots. However, for more permanent unbundling, the FERC intends to apply a 7-factor test for specifically identifying FERC jurisdictional transmission costs.[51] The 7-factor test is a more thorough process allowing for design of transmission rates for retail customers. After removing FERC transmission costs, the remainder of delivery costs would, by definition, be state-jurisdictional distribution and customer service costs. Board ratemaking authority would focus on these costs.

3.5 CONTRACTS

In determining effective competition, a potential issue may be whether prior long-term contracts between customers and utilities block competitive access by alternative providers. In restructuring the natural gas industry, one of the main impediments to effective competition was prior long-term contracts between natural gas producers and interstate pipeline companies. Settlement and removal of these contracts allowed the interstate pipelines to function as transportation-only entities, which provided customers direct open access to producer markets. In electric restructuring, long-term discount service contracts between customers and utilities may present a similar situation, except in this case the issue would be alternative providers gaining access to utility customers. Similar impediments may be presented by CESP contingency agreements, in which customers agree to take service from CESPs in the event their utility's service territory is opened to competition.

If policymakers provide open access for competitive generation, they may want to consider allowing customers to renegotiate all prior utility service contracts and CESP agreements, to allow all CESPs comparable competitive access to customers. In this way, all competitors would have the same starting point, similar to

[51] FERC Order 888, pp. 400-03, 435-40.

introducing competition by flash-cut (see Phase-In Versus Flash-Cut Section above).

APPENDIX A

MIDAMERICAN RETAIL ACCESS PILOT PROGRAM FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS

Background

The Board's NOI-95-1 Action Plan called for an Iowa-specific pilot program to test the direct access model for a subset of all customer classes. Specifically, a pilot was to be designed that would gather information on:

- Customer acceptance and understanding of retail choice;
- Customer information needs and ways to meet those needs;
- Potential benefits and costs of load aggregation in Iowa;
- Alternatives to individual time-of-use [i.e., real-time] meters; and
- Types of services which can efficiently be provided competitively to each customer class.

In addition, a pilot program would provide utilities with valuable experience, familiarizing them with the administrative processes and potential problems involved in direct access. Also, it would provide information about additional resources and organizational changes needed for broader implementation.

Earlier, settlement of the MidAmerican Energy (MidAmerican) alternative pricing proposal case (Docket No. APP-96-1) had produced a retail access pilot concept for large commercial and industrial customers. Pursuant to the settlement, MidAmerican proposed the concept as its Market Access Service (MAS) pilot program (Docket No. TF-97-229) on September 5, 1997.[52]

On February 10, 1998, in response to interest expressed by MidAmerican, the Board adopted NOI guidelines for a second MidAmerican retail access pilot that would be available to residential and small commercial customers. MidAmerican filed a pilot proposal in accordance with these guidelines (Docket No. TF-98-113) on May 4, 1998.[53]

MidAmerican's Residential/Commercial Pilot

MidAmerican's residential/commercial pilot will offer retail access to at least three percent of MidAmerican's residential and small commercial customers in a limited geographic area (yet to be announced).

---

[52] The Board approved MidAmerican's MAS pilot on August 21, 1998. The Board's rehearing decision was issued October 2, 1998.

[53] The Board approved MidAmerican's residential/small commercial pilot on August 21, 1998. The Board's rehearing decision was issued October 2, 1998.

Pilot participants will be allowed to directly purchase generation services from competitive suppliers. The suppliers will purchase unbundled transmission service from MidAmerican and resell it to pilot participants along with competitive generation. This unusual sale for resale arrangement is intended for the sole purpose of expediting FERC approval of unbundled pilot transmission rates based on MidAmerican's FERC open access transmission tariff (OATT). Suppliers are more likely than residential and small commercial participants to have the sophistication necessary to work with MidAmerican's OATT.[54] Pilot participants will directly purchase unbundled distribution services from MidAmerican.

MidAmerican will be allowed to market generation services as a competitive supplier through a functionally separate corporate unit. The corporate unit will operate under a code of conduct and a separate accounting plan.

MidAmerican, as the incumbent distribution utility, will retain control of meters and meter reading. MidAmerican will provide competitive suppliers with monthly meter reading data at incremental cost. MidAmerican will not require pilot participants to use real-time metering but, instead, will use load profiling for purposes of load balancing. MidAmerican will bill participants for their distribution service, and suppliers will separately bill customers for their generation and transmission service. However, participants may designate willing competitive suppliers as their paying agents for MidAmerican billings and, thereby, pay one monthly bill through their supplier. IUB consumer protection rules for deposits, bill payment, and discontinuance of service will apply to MidAmerican and competitive suppliers alike.[55]

In order to provide service in the pilot, suppliers must be able to: (a) purchase transmission through MidAmerican's OATT; (b) bill participants for supplier services; (c) exchange various forms of electronic information with MidAmerican; and (d) relieve MidAmerican of MAPP end-use load reporting responsibility for the loads suppliers serve. Suppliers are encouraged to secure a backup supply source with MidAmerican or another provider. If suppliers elect not to have backup supply and later require emergency backup, MidAmerican will provide the backup at 125 percent of market cost. Suppliers must provide the IUB with information about their pricing plans, billing formats, evidence of ability to provide service, and renewable ("green") energy content (if any).

The pilot will be preceded by a customer education plan developed in cooperation with the IUB and the Iowa Energy Center. MidAmerican will file

[54] In a broader restructured environment, utilities and regulators would likely have time to design unbundled transmission rates that are directly accessible by retail customers.
[55] Suppliers will agree to abide by applicable provisions of IOWA ADMIN. CODE § 199-20.4 as a condition of providing service in the pilot.

quarterly pilot progress reports with the IUB and assist the IUB and energy center in surveying pilot participants.

APPENDIX B

NERC CONTROL AREA OBLIGATIONS

It is impossible to precisely match the actual power interchange with scheduled power interchange. Therefore, a control area is required to keep the difference between the actual and scheduled interchange within North American Electric Reliability Council (NERC) specified limits and report these inadvertent power exchanges and other data, such as system frequency and area control error, to NERC on a regular basis.

A second control area obligation is to regulate and stabilize interconnection frequency. The scheduled frequency is usually 60 Hz or 60 cycles per second. The Automatic Generation Control (AGC) systems measure the frequency and adjust generation to change the actual frequency to match scheduled frequency of 60 Hz.

A control area is obligated to adhere to all NERC reliability criteria and operating guides. Regional councils and power pools also impose their own criteria and guides.

RECOGNITION AS A CONTROL AREA

To be recognized as a NERC approved control area, an interconnected electric system must meet the following basic requirements:

- Operate generation.
- Meter interconnections (ties) with other control areas and have the necessary contracts to use those connections.
- Control generation and match net actual interchange with net scheduled interchange.
- Has generator governors that are allowed to respond properly to interconnection frequency changes.
- Use tie-line bias control, unless doing so would adversely effect reliability.
- Have a control center with 24-hour staffing.

FERC ORDER 888 - ANCILLARY SERVICES

Services the FERC requires transmission providers to offer and customers to take from the transmission provider

Scheduling, System Control, And Dispatch Service
The control area operator functions that schedule generation operation functions before the fact. This also includes control of some generation in real-time to maintain generation/load balance. System control time frame is from seconds to

hours.

Reactive Supply And Voltage Control From Generation Source Service
The introduction or absorption of reactive power from generators to maintain transmission-system voltages within required levels. The time frame for this service is within seconds.

Services the FERC requires transmission providers to offer but which customer can take form the transmission provider, buy from third parties, or self-serve

Regulation Of Frequency Response Service
The use of generators equipped with AGC to maintain minute-to-minute generation and load balance within the control area to meet NERC standards. The time frame for this service is approximately one minute.

Energy Imbalance Service
The use of generators to hourly match actual and scheduled transactions between suppliers and their customers.

Operating Reserve-Spinning Reserve Service
Generators that are synchronized to the grid, are available to take additional load, and can respond immediately to correct for generation/load imbalances due to generation and/or transmission outages. Spinning reserve is fully available in ten minutes.

Operating Reserve-Supplemental Reserve Service
Generators and curtailable load that can be used to correct for generation/load imbalances due to generation and/or transmission outages within ten minutes. Unlike spinning reserve, supplemental reserve is not required to respond immediately.

Services the FERC does not require transmission providers to offer

Real Power Loss Service
Generators provide for transmission loss when power flows from generators to loads over transmission lines.

Dynamic Scheduling
Real-time metering, telemetering, and computer software and hardware to electronically transfer some or all of a generator’s output or a customer’s load from one control center to another.

APPENDIX C

TOOLS AND CONDITIONS NEEDED TO PREVENT COST SHIFTING AND CROSS SUBSIDIZATION BETWEEN REGULATED AND NON-REGULATED AFFILIATES

Purpose: A utility may wish to provide competitive services through the regulated utility as either a regulated or non-regulated service or through a non-regulated subsidiary or affiliate. It is important that the law allow the federal and state commissions to employ the tools necessary to prevent cost shifting and to ensure the competitiveness in unregulated markets is not adversely affected by interactions with regulated markets. This cannot be guaranteed if a commission must seek an agreement from a non-regulated subsidiary or affiliate in order to employ such tools.

A) Cost shifting between regulated and non-regulated affiliates shall be prevented through the following means:

1) <u>Federal Access to Books and Records</u>
The appropriate Federal Commission shall have access to all books, accounts, and records of all non-regulated subsidiaries or affiliates of a public utility.

2) <u>State Access to Books and Records and Personnel Capable of Responding to Inquiry from Regulators</u>
A state commission may examine the books, accounts, memoranda, contracts, and records and have access to personnel capable of responding to inquiries of:
a) a public utility subject to its regulatory authority under state law;
b) any non-regulated company, which is an affiliate, parent, or subsidiary of the state-regulated public utility company selling or receiving products or services to and/or from the state-regulated public utility;
c) any non-regulated company which is an affiliate, parent, or subsidiary of the state-regulated public utility company to determine if direct or indirect transactions have taken place between the non-regulated company and the state-regulated public utility. Where a state commission accesses the books and records of a non-regulated affiliate company, the state commission shall not publicly disclose trade secrets or sensitive commercial information;
d) any service company selling or receiving products or services to and/or from the state-regulated public utility;
e) any service company to determine if direct or indirect transactions have taken place between the service company and the state-regulated public utility. Where a state commission accesses the books and records

of a non-regulated affiliate company, the state commission shall not publicly disclose trade secrets or sensitive commercial information.

3) <u>"Ordinary Course of Business" Contracts</u>

The term "ordinary course of business", as it applies to contracts between affiliates that need not be approved by the federal and state commissions, should be clarified. It should be clarified that the transactions between the utility and the affiliate are for transactions which are customary for conducting regular utility business and that the goods or services being sold are typical for business transactions between a utility and another entity.

4) <u>Separation Plans or Operating Agreements</u>

a) A separation plan or operating agreement shall be filed with and approved by the federal and state commissions which ensures, to the maximum extent practicable, the operations, resources, and employees involved in the provision or marketing of non-regulated services, and the books and records associated with those services shall be separate from the operations, resources, and employees involved in the provision of state-regulated services and the books and records associated with the state-regulated services.

b) Item 4a above will apply even if the public utility company demonstrates a structural or physical separation of the regulated and non-regulated services.

c) Transactions between regulated and non-regulated service providers within the public utility company should be recorded in separate subaccounts to facilitate auditing by federal and state commission staff.

5) <u>Allocation of Costs</u>

a) Public utility companies should develop and maintain written guidelines for the methods used to allocate the costs of conducting and charging for or allocating transactions between regulated and non-regulated service providers within the public utility company. Such guidelines should be filed with and approved by the federal and state commissions.

b) Revenues received by state-regulated companies for services provided to non-regulated affiliates shall be recorded in "operating revenue" accounts, if corresponding costs were recorded in "operating expense" accounts.

c) Costs charged by regulated sectors to non-regulated sectors as affiliate transactions should be at fully allocated costs. In the case of a charge for facilities, the fully allocated costs should include at a minimum property taxes, depreciation expenses, maintenance expenses, and a rate of return on the investment in the asset. In the case of personnel, the

fully allocated costs should include all employee benefits, payroll taxes, insurance, pension, and post retirement benefits other than pension.
d) In cases where costs cannot be charged directly and it is necessary to use an allocation formula, revenues should not be a factor in the formula unless the utility can prove a direct causation with the revenues. Generally, revenue based allocations are not based on cost causation or utilization of resources.

6) <u>Audit Authority for State Commissions</u>
The state commission may order an audit to be performed no more frequently than on an annual basis, of all matters deemed relevant by the selected auditor that reasonably relate to retail rates.
a) The public utility company and the affiliated or associated companies involved in non-regulated services shall cooperate fully with all requests necessary to perform the audit.
b) In the event the state ordered audit is performed by an independent auditor, the public utility company and its affiliates shall bear all costs of having the audit performed.
c) The audit report shall be provided to the state commission not later than 6 months after the onset of the audit and provided to the public utility company not later than 60 days thereafter.
d) Transactions between regulated and non-regulated sectors should be subjected to regular internal audits by the public utility company. These audits should test compliance with all commission orders, compliance with proper accounting procedures and compliance with the written guidelines. The audits should included written reports of conclusions which, along with associated workpapers, are to be made available to the commission staff for review.

B) Tools to protect competitiveness and avoid subsidized or predatory pricing in unregulated markets:

Purpose: The same tools that the federal and state commissions need to prevent cost shifting also protect competitiveness of unregulated markets because they also prevent the non-regulated sectors from benefiting from lower costs than their competitors that result from shifting costs to regulated sectors.

In addition, non-regulated sectors or the regulated utility providing competitive services can benefit unfairly from free access to customer records of the regulated sectors. The non-regulated sectors, as well as the regulated public utility company, should be prohibited from unfair practices.

1) The regulated public utility company and its affiliates shall follow a code of conduct, filed with federal and state commissions, which governs the company's activities in a competitive market and the sharing of information, data bases, and resources between its employees involved in the marketing or provision of non-regulated services and those employees involved in the provision of regulated services.

2) The public utility company and its affiliates shall maintain records subject to federal and state commission review, which document compliance with the code of conduct.

3) The code of conduct shall include, at a minimum, the following <u>for any affiliate including service companies</u> engaged in competitive services:
a) the affiliate shall operate independently from the utility company;
b) the affiliate shall maintain books, records, and accounts in the manner prescribed by the appropriate federal and state commissions which shall be separate from the books, records, and accounts maintained by the utility company;
c) the affiliate shall have separate officers, directors, and employees from the utility company;
d) the affiliate may not obtain credit under any arrangement that would permit a creditor, upon default, to have recourse to the assets of the utility company; and
e) the affiliate shall conduct all transactions with the utility company on an arm's length basis with any such transactions reduced to writing and available for public inspection.

4) The code of conduct should include, at a minimum, the following <u>for the utility company</u> who has an affiliate engaged in competitive services:
a) the utility company may not discriminate between an affiliate and any other entity in the provision or procurement of goods, services, facilities, and information or in the establishment of standards;
b) the utility company shall account for all transactions with an affiliate in accordance with generally accepted accounting principles or accounting principles approved by the appropriate federal and state commissions; and
c) the utility company shall not carry out any promotion, marketing, sales, advertising, or research and development for or in conjunction with an affiliate.

APPENDIX D

NARUC ELECTRICITY SUBCOMMITTEE GUIDELINES FOR COST ALLOCATIONS AND AFFILIATE TRANSACTIONS

Each entity that provides both regulated and non-regulated services or products shall maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. Any entity required to provide notification of a CAM(s) shall make arrangements as appropriate to ensure the CAM and any information derived therefrom shall be kept in the strictest of confidence by the regulator and its staff. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company depicting all affiliates and regulated entities.
2. A description of all services and products provided between the regulated entity and its affiliates.
3. A description of all services and products provided by the regulated entity to non-affiliates.
4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

Entities will follow Statement of Financial Accounting Standards (SFAS) No. 131, *Disclosures about Segments of an Enterprise and Related Information,* as required and will make the disclosure available upon request to jurisdictional regulatory authorities.

APPENDIX E

SUMMARY OF ADVISORY GROUP COMMENTS ON STAFF'S DRAFT REPORT:

MAKING COMPETITION WORK: ADDRESSING ISSUES OF MARKET STRUCTURE AND POWER

DOCKET NO. NOI-95-1

STAFF OVERVIEW

Staff's draft report (report) focused on presenting a framework for addressing issues of market structure and power rather than on making specific recommendations for how the issues should be resolved. Therefore, the comments of the Advisory Group, summarized below, provide a useful complement to the report by providing specific recommendations based on the parties' issue positions. The comments are summarized by party and are organized according to the issue order presented in the report.

In addition to presenting issue positions, the Iowa Association of Municipal Utilities also comments on the organization of the report. First, it should be noted that the organization of the report is not intended to make rigid distinctions between end-state and transition issues. The end-state issues listed must necessarily be resolved during the transition period; the desired end-state would be defined prior to the transition period. As stated in the report's introduction, once the end-state is defined, transition measures, intended to achieve the end-state, must be put in place. Similarly, the two broad policy approaches to addressing market power abuse (i.e., restricting the market from the outset and letting the market develop and applying remedies as needed) are not mutually exclusive. In fact, several of the measures described, such as divestiture and mandatory ISO participation, can be used under either approach. Finally, in resolving the issues and developing policy implementation, additional detail will need to be developed. Again, the report focused on presenting a framework for addressing these issues rather than making specific recommendations for how the issues should be resolved.

MidAmerican Energy questions the report's blanket assertion that real-time metering provides a better match of estimated and actual loads than load profiling. The final report is amended to allow for MidAmerican Energy's view.

The parties' comments are as follows:

IOWA DEPARTMENT OF NATURAL RESOURCES

END-STATE ISSUES

Generation and Transmission Siting. The Iowa Utilities Board, rather than another state agency, should continue its role in conducting generation plant certification proceedings under IOWA CODE § 476A. Environmental criteria should be retained. Least-cost planning criteria should also be retained, adding a 10 percent externality credit for renewable energy options.

TRANSITION ISSUES

Contracts. If renegotiation of customer contracts with utilities is allowed, alternate energy producers should not be forced to renegotiate their contracts with utilities.

ALLIANT UTILITIES

END-STATE ISSUES

Price Deregulation. Staff's draft report suggests some form of continuing price regulation for incumbent providers during a transition to "effective competition." However, there can be no transition to competition without there first being price deregulation for all competitors.

TRANSITION ISSUES

Standard Offer Service. The discussion of standard offer service pricing makes the erroneous assumption that existing utility rates are cost-based. This is not the case with Alliant, as shown in the pricing differences between its northern and southern zones. The issue of standard offer service and default providers should also be addressed as an end-state issue. [STAFF NOTE: Staff's Universal Service Report addresses this.]

Phase-In Versus Flash-Cut. Flash-cut to competition is preferred, although a one-year phase-in might be acceptable. If large customers are phased-in on a percentage of load basis, there are fairness and administrative issues that should be addressed. Fairness issues include defining what customers are "large," what percentage of load is to be eligible, and what distinctions are to be made between firm and interruptible customers. Administrative issues include billing for customers who receive both regulated and competitive services.

MIDAMERICAN ENERGY

END-STATE ISSUES

Competitive Provisioning of Services. Contrary to Staff's draft report, load profiling will actually provide a better match between actual and forecasted customer loads for load balancing purposes than real-time metering. This is because similar load profiling models will be used to estimate the actual and forecasted amounts. Also, the report's discussion of ancillary services implies a greater state regulatory role than is actually the case. Ancillary services are regulated by the FERC. Metering and billing services should be open to competition, and incumbent providers should not be forced to provide them on a default basis. There are no demonstrated economies of scale for these services. Staff's draft report exaggerates the potential problems with reselling of delivery services. Regarding price protection, while it is important for customers to have limited protection during the transition period, it should be eliminated as soon as possible to foster competition. Price protection should have a definite termination date, with extensions only for specified periods if needed. Finally, the Iowa Utilities Board should not have unlimited discretion to open control area and delivery services to competition.

Market Power. Divestiture is highly disruptive and should not be considered as a possible administrative remedy for market power abuse. Structural separation (separate affiliates) is also too disruptive and, therefore, not an appropriate remedy. Functional separation (within the same corporate entity) is a more appropriate control measure. This would include codes of conduct, non-discriminatory access, and accounting separations. It may require the Iowa Utilities Board to have additional authority over electric cooperatives and municipal utilities. Effective functional separation would make mandatory ISO participation unnecessary. There should be no designated default provider. Customers should not be switched from their existing provider without their consent. Iowa's merger review procedures should not be changed. Market concentration and market power concerns are already adequately addressed in federal merger reviews.

Affiliates should be allowed to use their parent utility's name and logo. California and Illinois have allowed this. Surveys indicate that customers want their incumbent utility to be a competitor and want to be able to recognize its name. Also, since other market entrants will have recognized names, utility affiliates should be allowed to use recognized names as well. Any goodwill associated with a utility's name relates to its good management practice rather than its regulated expenditures. Therefore, it is a shareholder asset. Finally, affiliate use of a parent utility's name and logo is an exercise of free speech.

Affiliate Transactions. Functional separations with appropriate codes of conduct, cost allocations, and cost treatment are the most appropriate methods for preventing market power abuse. However, codes of conduct should not be used to force structural separations. Utilities and their competitive business units should be allowed to share in legitimate corporate economies of scope and scale that do not hinder competition, such as research and development. Transfers between utilities and their competitive business units should be based on market price. Transfer methods based on either the higher of book or market price, or the lower of book or market price, are arbitrary and unfair.

A utility's competitive unit should not be required to make royalty payments to the utility because it wrongly assumes that the benefit of utility association comes from the utility's ratepayers. As with use of the utility's name and logo, the benefit comes from corporate shareholders rather than ratepayers. Similarly, the concept of differential rates of return wrongly assumes the competitive unit should pay ratepayers for its association with the utility.

Generation and Transmission Siting. In generation siting, the least-cost planning criteria should be removed. Environmental and land-use criteria should be retained. However, the Iowa Utilities Board should consider obtaining the power of eminent domain to be used if generation is needed at particular sites for system reliability. In transmission siting, state land-use considerations may need to defer to federal authority if new line additions benefit the regional market.

TRANSITION ISSUES

Standard Offer Service. Standard offer service should be available only for a limited transition period, so that it does not hinder competition. Similarly, price cap restrictions should be relaxed to allow for recovery of any increased costs.

Phase-In Versus Flash-Cut. Phase-in, although more complex, provides a quicker introduction of competition and allows for the discovery and solving of implementation problems without affecting all customers.

Reciprocity. Both in-state and out-of-state reciprocity provisions are necessary to ensure equity and to prevent the use of integrated operations of other utilities from subsidizing intrusions into Iowa service territories.

Rate Unbundling. Cost-based unbundled delivery service rates may be preferred, but performance-based rates and other alternative ratemaking should be permitted. Also, for purposes of practicality, MidAmerican should be allowed to sell transmission services directly to CESPs for re-sale to retail customers.

Contracts. Prior contracts between MidAmerican and its customers were signed with the mutual knowledge that electric competition might be a possibility. These contracts should not be nullified. To do so would raise serious legal issues.

IOWA ASSOCIATION OF ELECTRIC COOPERATIVES

END-STATE ISSUES

Allowable Transactions. Bilateral transactions are preferable to the use of a power exchange. A power exchange would be expensive to develop and is unworkable without an effective regional ISO.

Competitive Provisioning of Services. Generation should be fully competitive, with minimum entry barriers for smaller entities, and minimum regulation. Price deregulation should be granted for competitive generation from the outset. Continuing regulation of generation will impede the development of effective competition. Competition should be limited to generation services, to avoid customer confusion. Delivery service and exclusive service territories should continue to be regulated. Control area operations might also be regulated and should be conducted by business units separate from the delivery service units to minimize affiliate abuses. All generation and delivery service providers should be allowed to require use of their own metering and billing services.

Market Power. Divestiture is not yet required to open the generation market to competition. Divestiture should not be considered unless investor-owned utilities (IOUs) use market power to block competition. Functional separation and codes of conduct should provide sufficient protection against IOU market power abuse. The Iowa Utilities Board should monitor IOU market power during the transition period. Electric cooperatives have no profit motive and do not have sufficient market share to present market power concerns. Therefore, electric cooperatives should have a lesser form of functional separation that allows for employee sharing. Otherwise, complete functional separation will be too costly for electric cooperatives and will bar them from entry into the competitive market. A workable ISO would be useful in facilitating market interaction but does not seem necessary for controlling IOU market power. There is not yet a consensus for developing a regional ISO, and it would be unreasonable to delay competition until one has been formed.

Affiliate Transactions. Codes of conduct governing affiliate transactions should recognize differences between IOUs and electric cooperatives. Unlike IOUs, electric cooperatives are smaller utilities that do not have a profit motive. Therefore, any requirements for separate subsidiaries and separate staffing would be unnecessary and unduly costly for electric cooperatives. Similarly, electric cooperatives should not be subject to audit review or rate regulation by the Iowa Utilities Board. Any electric cooperative affiliate transactions and codes of conduct should be reviewed by electric cooperative local governing boards and, if necessary, by the courts.

Generation and Transmission Siting. In generation siting, the least-cost planning criteria should be removed, and environmental and land-use criteria should be retained. In transmission siting, deference should be given to federal land use decisions.

TRANSITION ISSUES

Standard Offer Service. Electric cooperatives are willing to act as default providers, but their prices should not be artificially capped below the cost of providing service.

Phase-In Versus Flash-Cut. A flash-cut approach assures that competition will be available to all customers at the same time. Lack of utility readiness should not be used as an argument for phase-in.

Reciprocity. In-state reciprocity is reasonable. Out-of-state reciprocity may not be enforceable.

Rate Unbundling. Rate unbundling should take place at least six months before the start of competition and should be subject to the approval of electric cooperative local governing boards rather than the Iowa Utilities Board. However, electric cooperatives would be willing to publicly post their unbundled rates on the Board's web site.

IOWA ASSOCIATION OF MUNICIPAL UTILITIES

The emergence of effective competition and control of market power must be addressed during the transition and not left entirely to the end-state.

END-STATE ISSUES

Allowable Transactions. Staff's draft report states that the best market structure for Iowa depends, in part, on the emergence of aggregators. The definition of a sufficient number of aggregators, as well as other criteria for determining the best market structure, need to be identified. These criteria should include the market structure's ability to address: (1) market power caused by transmission constraints; (2) lack of a workable ISO; and (3) market power gained through mergers. Market power can be minimized by market structure selection and also by measures outlined in the Market Power section of Staff's draft report (see discussion below).

Competitive Provisioning of Services. Staff's draft report states that price deregulation "could be predicated on a showing that effective competition exists for a service." If so, the criteria for determining "effective competition" need to be identified.

Market Power. The control of market power is a transition issue as well as an end-state issue. In addressing market power, Staff's draft report identifies two basic approaches: (1) restrict the market from the outset; and (2) allow the market to develop relatively unconstrained and address market power abuses as they develop. These two approaches should be used together in an iterative manner. They should not be viewed as mutually exclusive.

For monitoring market power, the Iowa Utilities Board should: (1) determine what types of data to collect, including data from competitors; (2) determine the level of resources available for the task; (3) supplement limited resources by making data publicly available and encouraging monitoring by market participants; and (4) provide a complaint procedure for competitive abuses. In addition to the Herfindahl-Hirschmann Index (HHI) mentioned in Staff's draft report, the Board should use other methods for analyzing market power that: (1) discern market concentration trends; (2) take into account market history and the residual effects of long-term monopoly power; and (3) account for the lack of distinction among wholesale and old and new retail products. New market entrants should be monitored for market power the same as incumbent providers. New entrants might be affiliates of incumbent providers in other jurisdictions.

As Staff's draft report points out, a workable ISO has not yet been developed. Therefore, the Board should collect and analyze data on transmission constraints and implement remedies as needed, such as price caps for load pockets with limited transmission access.

For merger policy, the Board should consider a moratorium on future mergers until it develops methods for analyzing market power. The Board should also consider seeking conditioning authority that would allow it the option of reopening mergers, for a limited time after approving them, as market conditions warrant.

Market power can also be controlled by: (1) providing competitors access to customer information on a non discriminatory basis; (2) blocking any attempts by incumbent providers to lock in current market power advantages, such as metering service, prior to competition; and (3) setting limits on market share.

Affiliate Transactions. As with market power, this is a transition as well as end-state issue. Incumbent providers offering competitive services should do so through a separate affiliate, governed by a code of conduct that addresses what resources may be shared between the utility and its affiliate.

Generation and Transmission Siting. For generation siting, any changes in need or least-cost planning requirements should not discriminate against new market entrants and should adequately account for the public policy goals of least-cost planning during the transition. Transmission siting decisions should not discriminate against new market entrants.

TRANSITION ISSUES

Phase-in Versus Flash-Cut. There should be neither a phase-in nor a flash-cut to competition until: (1) incumbent providers are willing to turn over control of their transmission systems to an ISO; and (2) regulators have the authority to mitigate market power caused by transmission constraints. If incumbent providers withhold their cooperation in mitigating market power, then their competitors should be allowed to begin offering competitive services.

Reciprocity. Reciprocity is generally anti-consumer, anti-competitive, and illogical. It only benefits incumbent providers and hurts everyone else. Also, out-of-state reciprocity is an unconstitutional restraint of interstate commerce under the Commerce Clause.

REFERENCES

Alexander, Barbara R., "Comparison of Consumer Protection Provisions in State Legislation on Retail Electric Competition," March 1998.

American Public Power Association, "State Legislative Regulatory Restructuring Summary," June 15, 1998.

"Arkansas Commission Calls for Retail Competition No Later Than Jan. 1, 2002," Electric Utility Week, September 7, 1998.

Arizona Corporation Commission, "Comments From the Residential Utility Consumer Offices," October 29, 1997.

Arizona Corporation Commission, "Unbundled Services and Standard Offer Working Group Report to the Commission." (http://www.cc.state.az.us/ working/ unbundle.htm)

Baer, William J., "FTC Perspectives on Competition Policy and Enforcement Initiatives in Electric Power," December 4, 1997. (http://www.ftc.gov/speeches/ other/elec1204.htm)

Binz, Ronald J. and Mark W. Frankena, "Addressing Market Power: The Next Step in Electric Restructuring," Competition Policy Institute, June 24, 1998. (http://www.cpi.org/marketpower.pdf)

"Blackouts: Is the Risk Increasing," Electrical World, April 1998.

Borenstein, Severin, James Bushnell and Christopher R. Knittel, "Market Power in Electricity Markets: Beyond Concentration Measures," Power Working Paper Series - PWP-059, April 1998.

Brubaker and Associates, Inc., Industry Restructuring Newsletter, January 1, 1998.

Burkhart, Lori A., "From Statehouse to Your House: The Electric Competition Debate in . . . New York," Public Utilities Fortnightly, May 15, 1998.

"Competition Deregulation: Is The US Rushing Into Dark?" Special Report, Electrical World, October 1996.

Costello, Kenneth and Kenneth Rose, "Some Fundamental Questions on Market Power: No Easy Answers for State Utility Regulators," The Electricity Journal, July 1998.

Costello, Kenneth, “Fair Competition in Retail Electricity Markets,” The National Regulatory Research Institute, June 1998. (http://www/nrri.ohio-state.edu/ download/faircomp.pdf)

Edison Electric Institute, “Comments,” Inquiry Concerning the Commission’s Merger Policy Under the Federal Power Act, Docket No. RM96-6-000, Federal Energy Regulatory Commission, May 7, 1996.

ELCON, “Independent System Operators,” Profiles On Electricity Issues, Number 18, March 1997.

"Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities," DOE/EIA-0614, August 1997.

Faruqui, Ahmad and Laurence D. Kirsch, “Unbundling Electric Discos Overseas and at Home,” Public Utilities Fortnightly, April 1, 1998.

Federal Energy Regulatory Commission, Order 888, Docket Nos. RM95-8-000 and RM94-7-001, April 24, 1996.

Federal Trade Commission, Bureau of Economics, Comments of the Staff filed June 19, 1998.

Fink, Lester, “Ancillary Transmission Services,” The Electricity Journal, June 1996.

Frankena, Mark, “Prepared Testimony,” In Re Commission Investigation into Issues Regarding Electric Restructuring, Docket No. 95-9022, January 31, 1997.

Georgia Public Service Commission, In Re: Complaint of PanCanadian Energy Services, et al., Docket No. 9156-U, 1998.

Gordon, Kenneth, “Testimony On Behalf of the Edison Electric Institute Submitted to the Illinois Commerce Commission Docket Nos. 9800013 and 98-0035 (Consolidated),” National Economic Research Associates, March 11, 1998.

Graniere, Robert J., “Horizontal Market Power in Generation,” The National Regulatory Research Institute, May 1998.

Guth, Louis A, “An Overview of Market Power Issues in Today’s Electricity Industry,” The Electricity Journal, July 1998.

Hill, Lawrence J., “Economic-Efficiency Consideration in Restructuring Electric Markets,” Oak Ridge National Laboratory, ORNL/CON-436, December 1996.

Hirst, Eric, and Brendan Kirby, "Ancillary Services: The Neglected Feature of Bulk-Power Markets," The Electricity Journal, April 1998.

Hirst, Eric, and Brendan Kirby, "Electric Power Ancillary Services," ORNL/CON-426, February 1996.

"In Major Reversal, Michigan Industrials Call for Abandoning Deregulation Effort," Electric Utility Week, September 7, 1998.

Indiana Utility Regulatory Commission, "1998 Restructuring Activities By State," June 2, 1998.

Iowa Utilities Board, "Order Adopting Pilot Project Guidelines for MidAmerican Energy Company," Docket No. NOI-95-1, February 10, 1998.

Iowa Utilities Board, "Regulatory and Restructuring Options in the Electric Industry (A Discussion Paper)," Docket No. NOI-95-1, April 1996.

Iowa Utilities Board, "Regulatory and Restructuring Options in the Electric Utility Industry (A Staff Analysis)," Docket No. NOI-95-1, January 1997.

Kahn, Alfred, "Electric Deregulation: Defining and Ensuring Fair Competition," The Electricity Journal, July 1998.

Kahn, Alfred, "Numerical Techniques for Analyzing Market Power in Electricity," The Electricity Journal, July 1998.

Kirby, B. and E. Hirst, "Ancillary Service Costs For 12 U.S. Electric Utilities," Oak Ridge National Laboratory, ORNL/CON-427, March 1996.

Kirby, B and E. Hirst, "Unbundling Generation and Transmission Services for Competitive Electricity Markets: Examining Ancillary Services," NRRI 98-05, January 1998.

Kirsch, Laurence, and Harry Singh, "Pricing Ancillary Electric Power Services," The Electricity Journal, October 1995.

Kroll, Heidi and Richard Rosen, "Market Power, Mergers, and Deregulation: A Critique of the FERC's New Merger Guidelines," The National Regulatory Research Institute Quarterly Bulletin, Vol. 18, No. 2, Summer 1997.

LEAP Letter, March-April 1998.

Little, M. Bryan; “Wheeling Reciprocity: By Checklist or Certification,” Public Utilities Fortnightly, June 15, 1998.

Loehr, George C., “Ten Myths About Electric Deregulation,” Public Utilities Fortnightly, April 15, 1998.

Maine, Electric Service Customer Choice and Rate Relief Law of 1997, HB 362, December 16, 1997.

Maine Public Utilities Commission and Department of the Attorney General, “Market Power in Electricity,” Interim Report to the Joint Standing Committee on Utilities and Energy of the Maine Legislature, February 2, 1998. (http://www. state.me.us/mpuc/lr-mktpwr.pdf)

Maine Public Utilities Commission, “Order Provisionally Adopting Rule and Statement of Policy Basis (February 11, 1998) Rulemaking,” Docket No. 97-739, Chapter 301-Standard Offer Service.

Maine Restructuring Report, “Report on the Implementation of P.L. 1997, Chapter. 316 ‘An to Restructure the State’s Electric Industry,’” December 30, 1997.

Maryland Public Service Commission, Order No. 73834, Case No. 8738.

Masiello, Ralph D., “Integrating Metering and Information Systems,” Public Utilities Fortnightly, February 1, 1998.

Massey, William L., “Market Power and Competition in Electricity,” The National Regulatory Research Institute Quarterly Bulletin, Vol. 18, No. 2, Summer 1997.

McCullough, Robert, “California’s Electricity Market: Are Customers Necessary?,” Public Utilities Fortnightly, July 15, 1998.

Michigan Public Service Commission, “Customer Focus Issues and Recommendations,” Report filed by the Michigan Public Service Commission Staff, on October 13, 1997.

Michigan Public Service Commission, Case No. U-11290, Opinion and Order, June 5, 1997.

Michigan Public Service Commission, “Staff Market Power Discussion Paper,” Case No. U-11290 Electric Restructuring, June 5, 1998. (http://ermisweb.cis.state.mi.us/mpsc/ electric/restruct/mktpwr/finmkpwr.pdf)

Number 9.

North American Electric Reliability Council, “Control Area Concepts and Obligations,” July 1992.

North American Electric Reliability Council, “Glossary of Terms.” (http://www.nerc.com/glossary/glossary-body.html)

National Association of Regulatory Utility Commissioners, Committee on Electricity, White Paper: "Tools and Conditions Needed to Prevent Cost Shifting and Cross Subsidization between Regulated and Non-Regulated Affiliates," 1997.

National Association of Regulatory Utility Commissioners, “Electric Restructuring Legislative Reference,” June 4, 1998.

National Association of Regulatory Utility Commissioners, Staff Subcommittee on Accounts, “Guidelines for Cost Allocations and Affiliate Transactions,” 1998.

National Regulatory Research Institute, “A Cooperative Approach Toward Resolving Electric Transmission Jurisdictional Disputes,” NRRI-95-06, March 1994.

National Regulatory Research Institute, “Electric Industry Restructuring,” April 5, 1998.

National Regulatory Research Institute, “Summary of Key State Issues of FERC Orders 888 and 889,” NRRI 97-08, Revised January 1997.

National Regulatory Research Institute, “Unbundling Generation and Transmission Services For Competitive Electricity Markets: Examining Ancillary Services,” NRRI-98-05, January 1998.

National Rural Electric Cooperative Association, NRECA Retail Wheeling Report, June 1998.

New Hampshire Public Service Commission, “DR 96-150 Electric Utility Restructuring,” Order No. 22,875, March 20, 1998.

Missouri Workin
Other Competiti
(http://www.eco

Montana, Electri
Amending Title

New Hampshire Public Service Commission, "Restructuring New Hampshire's Electric Utility Industry: Final Plan," Docket No. DR-96-150, February 28, 1997, pp. 80-85.

Olson, Wayne P., "From Monopoly to Markets: Milestones Along the Road," Occasional Paper #25, The National Regulatory Research Institute, August 1998.

Pennsylvania, The General Assembly of Pennsylvania, House Bill 1509, Session of 1995.

Pleat, George R., "Should Metering Stay at the Stand-Alone Disco," Public Utilities Fortnightly, February 1, 1998.

Public Utility Commission of Texas, Rulemaking to Address Affiliate Activities, Project Number 17549. (http://www.puc.state.tx.us/rulemake)

Radford, Bruce W., "Electric Meter Deregulation: Potholes On the Road to Plug-and-Play," Public Utilities Fortnightly, September 15, 1998.

Radford, Bruce W., "NEV's Mike Peevey: Meters Make the Market," Public Utilities Fortnightly, June 1, 1998.

"Satellites Provide Low-cost Link To Remote Substations," Electrical World, December 1997.

Schuler, Joseph F., "Energy Service Companies: No More Mr. Niche Guy," Public Utilities Fortnightly, April 15, 1996.

Schuler, Joseph F., "From Statehouse to Your House: The Electric Competition Debate in . . . Ohio," Public Utilities Fortnightly, May 15, 1998.

"Seeing Dearth of Standard Offer Supply, Bids WMECO Wants to Remove Price Cap," Electric Utility Week, May 18, 1998.

Seiple, Christoper et. al, "Is the Market Working Properly?" Public Utilities Fortnightly, September 15, 1998.

Shepard, William G., "Market Power in the Electric Industry: An Overview," The National Council on Competition and the Electric Industry, November 1997. (http://eande.lbl.gov/ea/NationalCouncil/pubs/mktpower.pdf)

Smith, William H., Jr., "Nonutility Lines of Business Get Higher Regulatory Scrutiny," Natural Gas, July 1995.

Surrat, Walter, "The Analytical Approach to Measuring Horizontal Market Power in the

Electric Utility Markets: A Historical Perspective," The Electricity Journal, July 1998.

Swanekamp, Robert, "Moving Power to Market: Plants Will Shoulder More Burden," Power, March-April 1998.

Sweetser, Al, "Measuring Market Power in a State with a Dominant Supplier: A Case Study," The Electricity Journal, July 1998.

Trebing, Harry M., "Concentration and the Sustainability of Market Power in Public Utility Industries," The Regulatory Assistance Project, March 1998.

Vermont Public Service Board, "The Power to Choose: A Plan to Provide Customer Choice of Electricity Suppliers," Report and Order, Docket No. 5854, December 31, 1996.

Virginia State Corporation Commission, Staff Report, "Market Power," Chapter 3. (http:/dit1.state.va.us/scc/news/streprt3.htm)

Warwick, W. Michael, "Top 10 Lessons from Competitive Power Purchases," HPAC, August 1998.

Werden, Gregory J., "Identifying Market Power in Electric Generation," Public Utilities Fortnightly, February 15, 1996.

Wisconsin, 1997 Wisconsin Act 204.