THE DEVIL *IS* IN THE DETAILS

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INTRODUCTION

The Energy Policy Act of 1992 stimulated debates about the future structure and regulation of the electricity industry. The California Public Utilities Commission's April 1994 "Blue Book" and May 1995 proposals, as well as the Federal Energy Regulatory Commission's (FERC's) March 1995 mega-NOPR further stimulated these debates. As we reviewed the testimonies filed in these and other regulatory proceedings, the presentations at many recent conferences on industry restructuring, and the papers published in journals like this one, we were struck by the lack of detail and specificity. Too many speakers and writers dealt only with the broad issues in their comments on preferred industry structure and regulation, but left the details to others. (We believe that many organizations are working on the details of various proposals, but they are not, for competitive reasons, releasing these analyses.) For example, declarations of 17 interdependent principles are of little use if, taken together, they are internally inconsistent.

This paper shows that the details and specifics are important, perhaps as important as the policy issues. In a few cases, the details are outcome determining in that they will help policy makers decide on the overall course of direction. In many cases, the details can be worked out after overall policies are decided. In almost all cases, however, the details *are* essential to the creation and operation of an economically efficient, reliable, environmentally benign, and socially equitable U.S. electric system.[*]

The various proposals for new industry structure and regulation differ both in the length of the transition period and in the final structure itself. Some proposals call for almost immediate changes that would allow all retail customers to select their electricity suppliers. Others allow gradual increases in retail competition, with full retail wheeling occurring ten or more years from now. Some focus on wholesale competition, with retail customers continuing to be served by retail-monopoly-franchise utilities. Some people emphasize maintenance of various public-policy functions (e.g., resource-portfolio management, research and development, energy efficiency, and renewable resources) in a new industry structure.

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Some proposals call for today's utilities to deintegrate; that is, to divest themselves of their generation, transmission, and/or distribution assets. Some proposals call for an independent system operator who will, on a second-to-second basis, control the transmission network and enough generation capacity to maintain system stability and integrity. Other proposals would expand the role of the system operator to include the creation of a spot market for electricity, with prices that varied every hour in response to changes in customer demand and in generator offers.

POSSIBLE INDUSTRY STRUCTURE

Figure 1 shows one possible industry structure, chosen because it represents what we believe to be the ultimate structure of the industry. In this retail-competition scenario, the industry consists of six entities. Three of these entities—generating companies, marketers and brokers, and customer-service companies—are competitive and largely unregulated. Three of these entities—system operation, transmission, and distribution—are monopolies and would continue to be regulated. Under such a scenario:

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Fig. 1. Possible future structure of the U.S. electricity industry with full retail wheeling. The oval functions are competitive, and the rectangular ones are regulated monopolies.

A variety of independent power producers would build and operate power plants, subject only to siting and environmental regulations. That is, investors rather than governments would decide on the sizes, types, locations, and timing of new generating units. The output from these units would be sold through a variety of contracts (either directly to end-use customers or through marketers and brokers) or on the spot market.

The system operator would be responsible for matching generation to customer loads, given the constraints of the transmission network. The system operator would meet all the control-area requirements as specified by the North American Electric Reliability Council (NERC). As defined here, the system operator would own no generating units and no transmission facilities.

The transmission company would own and maintain transmission lines, substations, and other transmission-network components. Similarly, the distribution company would own and maintain local distribution systems.

The system operator and transmission companies would be regulated by FERC because their focus is on wholesale markets. State public utility commissions (PUCs), on the other hand, would regulate local distribution companies.

ERIC: Are state regulators likely to give up all transmission regulation?

Marketers and brokers would arrange financial and perhaps physical trades of electricity between generating companies and customers. Similarly, customer-service companies would offer metering, billing, information, and other services (such as energy efficiency and load management) to end-use consumers. Because these entities, like the generating companies, would be operating in competitive markets, they would be only lightly regulated. For example, PUCs might impose minimum service standards on all companies that sell electricity at retail. But PUCs would not conduct rate cases and would not set tariffs for different customer classes.

As examples of the kinds of details generally ignored in the presentation of restructuring proposals such as this one, consider the following questions:

What steps are required to create a competitive generation market? Would today's vertically integrated utilities have to divest themselves of their generating assets or would it be sufficient to have these assets operated by an affiliate functionally separate from the regulated utility? What criteria can regulators use to determine whether one or more entities have market power in generation (i.e., should utility generation be divested altogether or plant by plant)?

The lead items in this bullet seem to be criticl, if you screw it up very bad things will happen. I am not sure the remaining items are critical, you could probabbly go either way. The number of control centers ould probably change over time. They are more effeciency issues rather than critical issues.

Should ownership of transmission and distribution be separated? Should the system operator and transmission owner be one and the same? Should the geographic boundaries for the two be the same? Should some of today's roughly 150 control areas merge to create fewer, but larger control areas? How many control areas might be optimal within the three North American interconnections?

Where and how should performance-based regulation be used for the remaining monopoly elements: system operation, transmission, and distribution? What are suitable performance criteria for these three entities? How should such performance be measured? How would incentives for prevention of and recovery from outages be shared between the system operator and the transmission utility? And what are the tradeoffs between system reliability and least-cost operation of the system for the system operator?

Picking the wrong critera for performance-based regulation can serveirly warp the competative energy market. A system that rewards utilization of the transmission system could lead the system operator to favor long distance transactions. One that rewards minnimizing losses could lead the systeme operator to discourge use of the system.

Should distribution companies be wires-only businesses? Or should they permitted to provide energy services, either in competition with other entities or as the supplier of last resort (for those customers who cannot or do not want to obtain supplies from other sources)?

Should state regulators license marketers, brokers, energy-service companies, and other entities that sell electricity to retail customers? If so, what criteria would PUCs use to oversee these entities and to protect consumers? Which of today's technical and consumer protection requirements should be retained? For example, PUCs today specify maximum ranges for voltage at the customer meter, minimum accuracy for customer meters, and grievance procedures to resolve customer complaints about bills, service, or other matters.

Should the system operator adhere to NERC (1994) operating guidelines and rules? NERC developed these technical procedures through an industry-consensus process to ensure that today's electrical system operates reliably. Today's system is characterized by only a few participants with roughly comparable assets and interests

and, therefore, with strong incentives to work together. In the future, electric markets will include many more participants with a much greater diversity of assets and interests. In this new environment, will additional regulatory oversight be needed to adjudicate among the much greater diversity of participants and their perspectives? Or will the voluntary, consensus approach to creation, implementation, and enforcement of engineering standards continue to work well? Will a new industry structure require different standards? For example, will it still be important to maintain tight limits on frequency at 60 Hz? Must area-control error be driven to zero every ten minutes or would longer time periods suffice? The issue is not whether the current operating rules are "correct" but whether the proposed industry structure provides the necessary incentives to all market participants to continue such consensus rulemaking?

I think this is a very big issue. Perhaps it should be moved to the begining.

ANCILLARY SERVICES

For purposes of this article, we focus on ancillary services to show how important the details are. Ancillary services are those generation and transmission functions that support and are required to provide the basic electrical services of generation capacity, energy supply, and power delivery (Kirby, Hirst, and VanCoevering 1995). We focus on these services because the illustrate well our concerns about the relationship between the big picture and the details, they embody the conflicts between engineering standards and competitive markets, and the treatment of ancillary services can affect the resolution of other issues, such as treatment of stranded commitments.

FERC (1995) identified six such services, while we identified 19 (Table 1). Which, if either, list identifies the "correct" ancillary services? Are the seven services identified by ORNL but not by FERC of little importance and insignificant in cost? Should the costs of those seven services be included in the network-integration tariffs or should they be treated as a bundled set of ancillary services?

Table 1. Comparison of FERC and ORNL classifications of ancillary services

FERC	ORNL
Reactive power/voltage control	System reactive power management and voltage control Local reactive power management and voltage control
Loss compensation	Real-power-loss replacement
Scheduling and dispatching	Unit commitment Economic dispatch
Load following	Load-following spinning reserve
System protection	Reliability spinning reserve Supplemental operating reserve Stability enhancement reserve Local-area security Transmission reserves
Energy imbalance	Unscheduled energy
Services not identified by FERC	Time correction reserve Nonoperating reserve Black start Transmission monitoring and control Repair and maintenance of network Metering, billing, and communications Power quality

Other questions may be more important. Which ancillary services are required and which are optional? For example, most people agree that spinning reserves are required to maintain system reliability and stability. That is, the system operator must have under its control sufficient generation to meet time varying loads (both small fluctuations and daily ramping requirements) and to provide backup for forced generation and transmission outages. On the other hand, a customer could provide its own local reactive-power support. And energy imbalance may not be a service at all, as discussed below.

How should decisions be made on the tradeoffs between minimum engineering standards [e.g., NERC (1994) guidelines and requirements] vs having the system operator procure them competitively? For example, the system operator could specify a minimum power-factor capability (e.g., 90% or lower) for all generators that connect to the grid. Alternatively, the system operator could conduct periodic auctions and accept bids from generators and transmission-system owners to supply reactive power.

How should the system operator obtain generation-reserve services from suppliers? These services, provided by unloaded generating capacity plus governors on the generators and automatic-generation control systems, allow the control area to respond to changes in generation and load, both within the control area and in other parts of the interconnection. The rapid ramp rate (MW/minute) of some generators is a valuable feature that the system operator needs to meet the NERC area-control-error requirements. And the inertia of some generators (i.e., the ability of the unit to provide additional power almost immediately by slowing down slightly) aids system stability. How should these various services be obtained and paid for?

What gaming problems might occur when ancillary services are unbundled and priced separately if prices are based on "average" usage? Will power marketers, brokers, and others find ways to arbitrage small differences to make money? For example, FERC proposes to assign all wholesale transactions a transmission-loss factor of 3%. In reality, losses vary with time and location. Indeed, transactions that flow in the opposite direction of most flows may result in negative losses (i.e., implementing these transactions will reduce system losses). If low-loss customers are able to strike special deals, the system operator will face losses that are now larger than the formerly computed average. Although ancillary services account for only 5 to 10% of the total cost of generation and transmission, the resultant cost of ancillary services is still about $10 billion a year. Surely, this is enough money to motivate competitors to find profitable niches. If these niches impose costs on other market participants (either generators or customers), then these niches need to be redefined.

How does provision of ancillary services (and who can provide these services) differ when the scheduled power (1) flows entirely within a control area, (2) flows from within to outside the control area, (3) flows from outside to within the control area, or (4) flows across the control area? We think the answer to this question depends primarily on the location of the customer; e.g., spinning reserves must be provided by the local control area in cases 1 and 3. On the other hand, losses and voltage support are required in all four cases. Others may hold different views on whether and which ancillary services can be provided remotely (i.e., from outside the local control area) and which control area is responsible for the provision, costs, and pricing of which services.

To illustrate the importance of details, we discuss below three ancillary services: load-following spinning reserve, reliability spinning reserve, and energy imbalance.

LOAD-FOLLOWING SPINNING RESERVE

Utilities today maintain extra generating capacity online to respond to the rapid fluctuations in customer load. Typically, utilities provide 1 to 3% of capacity for this purpose. All customers pay for this capacity through bundled rates.

In a competitive market, utilities could charge for load-following at a uniform rate for all customers regardless of their load variations. Alternatively, utilities could charge customers for the specific load-following burden placed on the control area.

The former approach is simple, consistent with the current system, and inequitable. An electric-arc furnace, with a load that varies by several hundred MW from second to second, would pay the same for load following as a paper mill, with a near-uniform load.

The second approach is more complicated, consistent with the notions of a competitive market, and equitable. Each customer would pay for the load-following burden that it placed on the control area. Unfortunately, calculating that burden could be complicated because it is not the *individual* load variation that imposes costs on the control area, but the *aggregate* load variation. Thus, the system operator would have to calculate the covariance between a customer's time varying load and that for the total control-area load. Given such information, the customer could choose to pay the system operator for its load-following costs. Or it could reduce its burden on the system by reducing the load fluctuations seen by the control area. The customer could more carefully manage its load to reduce fluctuations or it could install energy storage or generation equipment onsite[#] to counteract the load fluctuations that would otherwise be seen by the control area.

RELIABILITY SPINNING RESERVE

While utilities maintain load-following reserves to track the moment-to-moment variations in customer loads, they also maintain reserves to compensate for the unexpected loss of generation or transmission capacity. Thus, reliability spinning reserve is the supply-side equivalent of the customer-side load-following reserve. Load-following reserves respond to the many small changes in customer load, while reliability reserves respond to the occasional large changes in supply capacity. Utilities typically maintain 1 to 3% of capacity on line for reliability purposes, for which all customers pay through bundled rates.

In a competitive market, utilities could charge suppliers (generators or power marketers) a uniform rate for this service. Alternatively, utilities could impose customized charges based on each generating unit's reliability (i.e., its forced outage rate).

The former approach is simple, consistent with the current system, and inequitable. This approach is inequitable because it imposes the same costs on all generators, regardless

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[#]The energy storage or generation could be remotly located or come from a remote supplier if dynamic scheduling were used.

of their reliability levels. The second approach would provide a clear incentive to generators to maintain their units at economically efficient levels of reliability. That is, generation owners would pay for enough maintenance so that the marginal cost of reducing outages would equal the marginal cost of reliability reserves.

ENERGY IMBALANCE

Energy imbalance (EI) seems to pose especially difficult questions about its purpose, costs, prices, and application. Energy imbalance is intended to compensate the local control area for (presumably small) discrepancies between actual and scheduled deliveries. FERC (1995) proposes to measure energy imbalance over one-hour periods. So long as the discrepancies are within a deadband of ±1.5% of the hourly schedule, the customer can return the energy in-kind under similar conditions within 30 days. For deviations outside the deadband, the customer, under FERC's proposal, would pay 100 mills/kWh.

The definition of energy imbalance raises several questions. First, if a customer obtains load-following and reliability spinning reserves from the local control area, can EI still exist? That is, won't the provision of these spinning reserves automatically cover any discrepancies that might otherwise be considered EI? NERC (1995) and others suggest that EI differs from load-following reserves in magnitude, with EI dealing with "larger mismatches" between actual and scheduled flows, but the magnitudes of these services are not specified.

Second, some utilities define other services such as deadband protection, standby service, and unauthorized use (Michigan Public Service Commission 1995). How these services differ from each other and from EI is unclear. One Southwestern utility identifies inadvertent interchange, backup services, and standby service without clear distinctions among the three services.

Third, should the price of EI be based on the out-of-pocket costs to the utility (primarily fuel, variable O&M, and opportunity costs)? Or should the price be based on the embedded cost of generation (which would include, in addition to the out-of-pocket costs, the capacity costs)? Or should EI be considered a penalty, with the price set high enough to discourage its use? Is the utility required to construct capacity to provide EI?

Still other questions concern the appropriate time period over which to measure EI and the magnitude of discrepancy allowed within its definition. Fig. 2 shows four hypothetical situations in which the schedule for that hour calls for delivery of 100 MW. In all four cases, EI is zero for the hour. In case A, the schedule and actual agree perfectly. That is, the customer consumes energy at a uniform rate of 100 MW throughout the hour. In case B, the customer's load varies slowly during the hour, from a high of 110 MW at the beginning to a low of 90

MW after 30 minutes, returning to 110 MW at the end of the hour. In this case, EI is again zero because the excesses and deficiencies exactly balance. Case C is the same as case B except for a much higher amplitude (50 MW instead of 10 MW). Finally, case D is the same as case C except for a much higher frequency (10 cycles/hour instead of 1). Although, when integrated over the 60-minute period considered, EI is zero in all four cases, the costs to the local utility of meeting these loads is surely different, increasing from A to B to C to D. These extra costs are a consequence of the degradation in heat rate, higher operations and maintenance costs, shortened lifetime, and opportunity costs for the generators that must follow the time-varying patterns of customer load.

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Fig. 2. Four hypothetical situations in which energy imbalance is zero for the hour, but during which imbalances vary substantially.

These examples suggest that measuring EI at the hourly level might encourage gaming on the part of suppliers and customers; perhaps EI should be measured every five or ten minutes. NERC uses 10-minute intervals for its A1 and A2 criteria to minimize area-control error. Clearly, FERC, utilities, and transmission customers face difficult questions in translating NERC's inadvertent-interchange concept, which applies to control areas, to the energy-imbalance concept, which applies to individual transactions.

SUMMARY

The many debates over the future structure and operation of the U.S. electricity industry are long on policy and philosophy and short on details and specifics.

Debates over the structure of wholesale markets emphasize different roles for the system operator. In the Poolco approach, the operator would create and manage a spot market for electricity with publicly available prices for electricity posted every hour. In the Bilateral-contracts approach, the system operator would focus solely on system reliability. Careful consideration of ancillary services might help to resolve this debate. Under the Poolco proposals, some of the ancillary services could be bundled into the overall rate and included as a uniform charge to all customers. Specifically, the concept of energy imbalance would not exist in a Poolco environment. In a Bilateral-contracts model, however, many of these services would be unbundled and priced separately.

A similar situation occurs with stranded commitments. Estimates of the potential costs to utility shareholders do not account for the use of what would otherwise be considered excess generating capacity to provide spinning reserves, supplemental operating reserves, and reactive power. These ancillary services might require about 10% of a control area's generating capacity. Accounting for these uses of generating capacity would reduce estimates of stranded commitments.

Our point is not that a narrow focus on implementation details will resolve all the policy questions. Rather we believe that we can move forward on policy decisions and their implementation only after more of the details have been worked out. Ultimately, decisions on industry structure will be largely judgmental, based on incomplete facts and analysis. But we have an obligation to ensure that decision makers understand well the consequences of the choices they face, based on the incomplete data and imperfect analysis we are able to provide them.

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