Getting It Right the First Time: The Value of Transmission and High Technologies

The transition to a competitive electricity market will require a more careful approach to intersystem coordination —planning, operations and pricing—than policy makers have yet recognized. But there's still time to get it right.

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—In Argentina ... industry participants are having a tough time agreeing on who will pay for a badly needed transmission line ...[1]

—Wall Street Journal

—... [W]e never deregulated safety. As we were deregulating in other ways—price and entry and competition—I went over to the Department of Transportation and said, "You're going to have to have more intense safety scrutiny ..."[2]

—Alfred E. Kahn

—I don't think our people really grasped the fact that ... Valujet grew faster than its systems and our ability to manage their growth.[3]

—David Hinson, Federal Aeronautics Administration

States have scheduled the starting date for retail wheeling. The government has opened the grid. Politically correct regulatory agencies declare that nobody will escape stranded costs. Engineers still warn about the need to maintain system reliability. But free marketeers have a ready answer: "Don't worry. The market will furnish the solutions." We would argue otherwise. Not because a market could not provide solutions, but because whole sectors of the electricity supply market have—so far—been omitted from the market.

Hurried deregulation on a piecemeal basis may create some local successes, but also lead to unanticipated failures in other parts of the system. A workably competitive market must value all the important aspects in the system, otherwise piecemeal incentives may invite failure. The savings and loan debacle,[4] the privatization of an oligopolistic generating sector in the United Kingdom,[5] and the liberalization of long-distance communications in Canada followed by the financial collapse of most new entrants within a year[6] are notable examples of misguided public policies that neglected a systems overview and did not get it right the first time.

Deregulators, we argue, should create—in advance of deregulation—a framework for the operation and expansion of the electric power industry which integrates technical and economic objectives into a reliable, real-time, near-optimal industry. Proper integration of existing assets into the framework and valuation of the services that they provide could reduce stranded assets, too. Achieving optimality, however, depends on economic and technical feedback operating in real time. Applying price incentives throughout could produce a decentralized, highly efficient, responsive electric supply industry that not only utilizes existing assets to their fullest, but also encourages capital expenditures when expansion is a better answer than rationing existing assets. The solutions to problems of reliability, stranded assets and investment may lie in applying more economic incentives for system support needed to facilitate the primary supply/demand market.

I. Obstacles on the Way to an Efficient Open Access System

Presently, several conceptual obstacles lie in the path of successive deregulation of the power industry.[7]

(1) The interconnection,[8] consisting of and providing both transmission and ancillary services, is operated and planned by its subowners without a systematic assessment of the entire system. At the same time, suppliers use it as if it were a single entity. This situation raises profound questions regarding both the technical performance of such a system (reliability) and its efficiency.

Experience in other countries and industries provides examples of misguided public policies that neglected a systems overview and failed to get it right the first time.

(2) The pro forma tariffs for open access to the interconnection and cost compensation for ancillary services fall short of reflecting the actual use of the system. That fact is likely to create uneven incentives for the system to evolve from its present form into one capable of facilitating the supply/demand market in an effective and non-discriminatory manner.

(3) System operators have been requested to publicly provide real-time information as to their "available transmission capacity" (ATC). By now, however, the technical literature has shown many times that the ATC of the interconnection cannot be easily broken down into the ATCs of its subsystems (pools, utilities), because of loop flow and counterflow issues. No individual subsystem can sell its portion of the transmission "right" within the interconnection independently from the activities of other subsystems. Therefore, no capacity right can be assigned or traded at a subsystem level independently from the others.

(4) To confuse the issues further, regulators now present us with the idea of transmission capacity rights (one must read this as "system capacity rights," a much broader request). If not properly defined and priced, these rights are likely to create an enormous burden on providers of system services and induce great inefficiencies when planning for new enhancements of the system.

(5) Furthermore, the idea of a secondary market for transmission rights, as a means of dealing with uncertainties, is risky (and, we later argue, unnecessary as well). If a "right" is not a well defined notion, how can one "trade" it further?

Having said that the pro forma tariffs are not effective, and that physical transmission capacity rights cannot be defined in a decentralized way by the subsystems within a larger electrically interconnected system (i.e. open access system), we suggest a systematic look at the problem. Two qualitatively different ways of providing and pricing transmission services under open access are possible: (a) by the transmission provider, or (b) by interested primary market participants. In this article, only approach (a) is described. At present there is insufficient development on approach (b), so it is not discussed further.

Two distinct possibilities are considered in this article: that the interconnection will consist of many independent system operators (ISOs) making decentralized decisions within the interconnection, or that an additional well-designed coordinating ISO will serve to provide a minimal degree of necessary coordination of the individual ISOs and thereby ensure the reliability of the entire interconnection and its near-optimal dynamic efficiency.[9]

II. The Problem in the Context of Industry Structure

To fully understand the reliability and efficiency impacts of an economic transaction between a power seller and a power buyer on an interconnected system under open access—and, consequently, the role of system services in facilitating the transactions—it is essential to understand the underlying hierarchical structures of the interconnected system in a regulated industry, as well as the industry structures into which the system is likely to evolve.

At present, a typical electrically interconnected transmission grid is planned and operated in a horizontally structured manner by the subsystems (utilities, pools) defined according to the ownerships of portions of the grid. Transmission, generation and distribution

Two possibilities are considered here: that there will be many ISOs making decentralized decisions, or that a central ISO would provide the needed coordination.

are planned in each vertically integrated subsystem to accommodate the needs of the customers in each area, perhaps allowing for some prespecified ranges of power export/import to adjacent subsystems. The amount of exchange with the neighboring subsystems is planned independently[10] by each subsystem. Until recently, each subsystem had full jurisdiction over power generated, in terms of planning and operating all available resources in the area and allowing for their coordinated use. Performance objectives (both physical and technical) are restricted to each subsystem. There is no systematic planning of exports/imports among the subsystems. The supporting transmission system and ancillary services are designed accordingly for limited exchanges with the adjacent subsystems.

The number of subsystems of this type within the interconnection is very large.[11] In response to regulatory requirements for open access, the industry is working on functional consolidation of those subsystems into larger entities operated by some sort of ISO. Even when completed, this process would leave the interconnected system operating in a somewhat decentralized manner, in the absence of a coordinating ISO that is responsible for reliability and efficient planning and operation of the entire interconnection. The supply/demand patterns within this effectively identical organizational form, except for the size of subsystems, may become significantly different, driven by differentials in primary market prices across the entire electrical grid.

Given the regulatory requirement that open access must be provided to all (inside and outside each subsystem prior to creation of ISOs or, later, within and outside the ISO area) means, in effect, that access must be provided anywhere within the electrically interconnected system. As a consequence, the system is potentially vulnerable to both reliability and efficiency problems. The reliability of this new mode of operation—facilitation of primary supply/demand transactions across the entire interconnection by decentralized decision making of individual subsystems—will depend to a great extent on how well reliability standards are defined and enforced on and by regional ISOs, and further unbundled into the responsibilities at the primary level of each market participant.[12]

It is well known to theorists concerned with optimization of hierarchical network systems of this form that:

(1) The system-wide performance criteria (both technical and economic) can be fully optimized only by introducing a coordinating level.[13] For the electric power industry, this would require a coordinating ISO for the entire interconnection. Because of the dimensionality of the problem, this process would require the development of minimal level models, relating tie-line flow exchanges among the subsystems to the generation/demand that actively responds to the system-wide performance criteria.[14]

(2) Without a coordinating ISO, the system is, effectively, operated in a decentralized manner, with subsystems acting as individual ISOs. To guarantee system-wide reliability, it is essential to define and enforce meaningful performance objectives for and on each ISO. In theory, this solution is always less optimal than having a coordinating level ISO. More important, these distributed performance objectives are hard to define, primarily because, given different electrical properties of subsystems under the jurisdiction of individual ISOs, they are bound to be nonuniform. This problem, in turn, will create severe legal issues. The NERC Working Group on Interconnected Operations Services (IOS) is tackling this issue, but without getting to the heart of the matter.[15]

In order to provide some clarification of relevant performance criteria at each subsystem level and at the interconnected system level, we will briefly summarize performance objectives in the present organizational form. We will contrast the present situation to the environment being created, and then define the striking differences which we believe require a profound rethinking of system support under open access.

The reliability of this new market and mode of operation will depend to a great extent on how well reliability standards are defined and enforced on and by regional ISOs.

III. Performance Objectives at the Subsystem Level in a Regulated Industry

Operations planners try to achieve five tasks simultaneously:

(1) meet anticipated demand at the lowest operating cost,

(2) compensate for real and reactive transmissions losses,

(3) deal with operating constraints,

(4) provide real-time balancing generation to meet deviations from expected demand, and

(5) provide stand-by generation in case of an outage.

Economic dispatch and scheduling (task 1), loss compensation (task 2), and operating within the static operating constraints (task 3), are integral services provided by all generating units that participate in economic dispatch to meet anticipated demand. Only deviations from anticipated demand caused by small, random fluctuations rely on automatic generation control (AGC) (task 4). A large system has a few units directly dedicated to system-wide regulation in response to small, random fluctuations, the AGC units for frequency regulation. For system protection in the event of a major outage (task 5), however, the generation reserve is planned to use the most economic units whenever possible. Much sophisticated hardware, such as power system stabilizers and static Var compensators, is installed on the system to regulate system transients in response to unexpected events.

At present, operations planning for generation is at each subsystem level, with a single bundled objective—to perform all five tasks at the lowest possible total cost—in order to reach ideal technical efficiency for generation production.[16]

IV. Open Questions at the Subsystem Level

While all five tasks are performed today at each subsystem level using all available generating resources, the industry is moving toward performing task 1 in a competitive—not coordinated—manner. Our purpose here is to stress open questions related to tasks 2–5, and to suggest solutions, so that performing these tasks enables the supply market (task 1) to operate efficiently, and so the competitive market participants (CMPs) compensate those performing tasks 2–5 in a way that reflects use of those services.

Some tasks are unique to electric markets because of the limited ability to re-route power flows and store electricity.[17] Electricity planners face fundamental questions concerning tasks 2–5. Need all these tasks remain coordinated by the ISO of *each* subsystem? CMPs could perform some of the functions 2–5. If they do, however, some agency will have to specify minimal technical performance. If some services remain coordinated in real-time, an organization (e.g., an ISO) must also decide how to create and use the resources required to perform those services—which must be put in place prior to the time that they are used[18]—and how to price the services.

The major problem, though, is that tasks 2–5 depend on how task 1 is accomplished, because they balance the system when the main supply/demand market fails to do so. In addition, power quantities traded in the primary market may change once charges for services 2–5 are revealed. To solve the interdependency problem:

- *Either* create resources to meet tasks 1–5 in a coordinated manner, retain all technical services as they are now, and introduce coordinated mechanisms to produce market prices for bundled services (various poolcos propose this approach)
- *Or* perform some of tasks 2–5

at the end user level, and some at a subsystem level.

V. Performance Objectives at the Interconnection Level

At present, no systematic planning of exports/imports among the subsystems is done for efficiency reasons. The only coordination recommended by NERC is for reliability reasons. The subsystems of each reliability region observe the $(n - 1)$ criterion, which requires that no single contingency in the region should disrupt service to customers. It is important to recognize that coordination can only be defined at the interconnected regional level, i.e. by simulating the entire region and then defining limits on exports/imports to individual subsystems. The recommended export/import limits among the subsystems are quantifiable only by simulating the entire region. For example, it is difficult to study the impact on Pennsylvania of the failure of the HVDC line between Canada and New England by analyzing only these two subsystems within the NPCC.

In an environment of active trades across the entire region driven by generation price differences, it is essential for reliability to define limits on export/import patterns of each subsystem within the region. How to do this in a realistic way is an open technical problem, since this problem has not been studied systematically in the past. Even more important is the fact that no subsystem can exactly regulate its exchange with the adjacent subsystems. This is done by generation scheduling within each subsystem, and deviations are always likely because of the power deviations elsewhere on the interconnection. Moreover, quite often no subsystem has enough generation to schedule the defined exchange. This is accomplished in a bilateral manner at present, as one subsystem reduces and the other increases generation in its area. If they are not adjacent, this bilateral process may affect the other subsystems within the interconnection significantly. This mode is typical of wheeling requests. The net result is that the actual exchanges among the subsystems are *never* the same as the scheduled exchanges.

In the absence of any information about the rest of the region, it quickly becomes clear that ATC cannot be easily quantified.

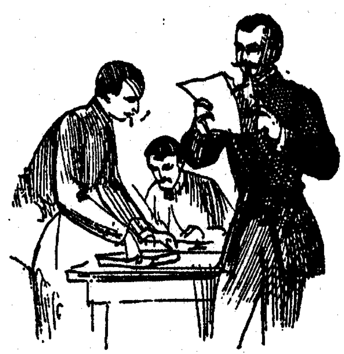
VI. Minimal Coordination for Tasks 2–5

A. Reliability Reasons

For successful operation of electric power systems under open access, a certain minimal level of coordination at the interconnected system level must be preserved. The most recent blackout in the Western U.S. is an example of what happens when two subsystems do not coordinate their activities. Events in the Northwest were not communicated in a timely manner to the subsystem in Northern California. Consequently, the actual tie-line flows between two subsystems were not the same as the scheduled flows. When a transmission line connecting these two subsystems went out of operation unexpectedly, the scenario played out had serious implications for the functionality of the western reliability region. Reliability is ultimately a question of careful coordination of various subsystems.[19]

B. Efficiency Reasons

In addition to reliability concerns, it is important to recognize that the efficiency of operating the interconnection under open access depends greatly on the type of pricing signals for the interconnected system services (transmission and ancillary services) furnished to the primary market participants. When developing pricing mechanisms for reliable operation, one must account for the economics of services unique to electric power systems (tasks 2–5). The solutions will run the gamut from those dominated by the competitive supply/demand processes, fudged with some cost estimates of "other" services to the primary market, to a near-optimal solution in which the economic impact of these services is taken into consideration by inducing pricing signals that discourage their use when not available or paid for.



In the remainder of this article we suggest a conceptual scheme for linking physical and economic processes by means of real-time signals for transmission and ancillary services provided by ISOs.

In concept, these signals should reflect the best possible estimate of the expected use of the transmission system and all other resources needed by the ISO to facilitate the primary market. These costs, depending on how they are computed and communicated to the CMPs, vary significantly. Preliminary documentation[20] indicates that usage-based pricing could make a big difference in the bottom-line energy bill seen by customers in a particular subsystem. If this bill is lower, the generation presently owned by the subsystem is more competitive with the generation in other subsystems. The "cherry picking" of customers across the interconnection, often involving large electrical distances, is caused, in part, by unrealistic pricing of services. Perhaps by the time transmission and system services are paid for a deal for wheeling power would not be as attractive as when the cost of these services is unrealistically small. The CMPs must realize that the *long run* cost of supporting transfer of power across very large electrical distances involves expensive technologies (computers, control, and communications (the 3Cs)) in addition to providing a transmission path.

There are definite tradeoffs in the marginal costs of operating the system which may be caused by (1) enhancing the system by means of such technologies or (2) employing more expensive generation to meet needs. Adequate price signals must reflect these differences.

An effective organization of ISOs ultimately has three major goals:

(1) Operate the interconnected system reliably under competitive access, including systematic curtailment of transactions in real time, when necessary.

(2) Plan the transmission system and ancillary services to facilitate the primary market.

(3) Provide meaningful access charges to the CMPs, which induce dynamic efficiency of the interconnected system. Without these signals, there will be no incentives for enhancing the system by means of 3C technologies and an improved transmission grid.

The network requires economic incentives to utilize 3C technologies. The role of technology in providing reliability, dynamic efficiency, and economic value is poorly understood. The lack of economic incentives to apply new technologies to the network is barely mentioned in restructuring discussions.

VII. Linking Physical and Economic Processes in a Distributed Industry: A Transition

Assuming equal consideration is given to additional metering, 3C technologies and transmission system enhancements on one hand, and to new generation technologies on the other, it would be optimal to treat the entire interconnection as a genuine open system when operating and pricing for transmission and system services.

An *a posteriori* allocation based on usage[21] would be necessary to divide cost among the subsystems (ISOs, pools, control areas, or whatever other form evolves). However, for an interconnected system as large and complex as we have in the United States, it is unmanageable to have one entity responsible for detailed operations of the entire system. Regulators must, therefore, precisely define "open access system" sub-areas of the large electrically interconnected system. It may be manageable to have at least as many interconnections, within which open access is confined, as we presently have regions for reliability. For reasons described above, ideally each of these regions should have a coordinating ISO with several ISOs under its jurisdiction. For purposes of further discussion here, no active trading outside these regional ISOs would be allowed.[22]

The number and size of the open access areas within the U.S. remains a serious technical and political question at present.

The number and size of the open access areas within the U.S. remains a serious technical and political question at present. Each reliability region is itself very complex and not manageable technically as one system because of the many control areas and decision makers involved. Regions that presently have tight power pools are likely to retain that structure. Other regions will probably evolve into tight power pools. Not much would change under this scenario, except that the present pool organizations become ISOs, to be coordinated, one hopes, by a single super ISO.

However, there are many important questions concerning management of the active primary market within each region. The major one is whether the approval of transactions and their pricing is given at each subsystem (ISO) level, or through the coordinating ISO.

One possible solution would be to define a division between transactions. Certain transactions would be handled by a coordinating ISO and others would be handled by the subordinal ISOs, depending upon the type of transaction. All transactions among buyers and sellers that are physically located within a subsystem could be fully managed at this level only. Longer term, large and somewhat firm transactions that cut across subsystems should be managed at the coordinating ISO level. The remaining, short term, non-firm transactions could be handled at each subsystem level. (It is basically unreasonable and technically difficult to implement in real time a short-term, non-firm spot market of the entire region.)

Under such a setup, each subsystem would be planned for all transactions within its area, while the interconnection would be planned for large, firm transactions across larger electrical distances. Well defined, active spot markets would be technically feasible only at each subsystem level (the size of a pool, or present day utility). When attempting to implement spot markets over an entire region, the process would quickly face lack of centralized communications between the coordinating ISO and the individual CMPs.[23]

This setup, with a coordinating and subordinate ISO, lends itself to the well understood principles of hierarchical power systems operation, with an additional burden of having to project the market for coordination at the interconnection level. It would be ineffective to plan system enhancements for short term, nonfirm spot markets. These markets consist of opportunities created by uncertainties and should be treated as such.

In this arrangement, CMPs must decide what type of transactions they wish to engage in, and bear the risks created by market uncertainties. Uncertainties presented by system constraints and the cost of services would be fully as important as those evolving in the primary supply/demand market level.

In a framework of this sort it would become redundant to require transmission capacity rights. The "right" would be given automatically to the participants in an economic transaction by the ISO, whose prime responsibility is to decide if contracts of various durations and firmness may be physically implemented. The instant this is done the only remaining question is what is an adequate open access charge. This is, again, best decided at the ISO level, since each transaction generally affects the entire interconnection. Making a capacity reservation for transmission capacity that may not be used only breeds inefficiencies.

The availability of the transmission grid on a non-firm basis must also reflect system input uncertainties. Actual inefficiencies caused by inability to transfer power would be directly reflected in managing the system at a suboptimal welfare cost. System planners could plan enhancements of the grid for expected system input dynamics. The investment risk caused by deviations from expected values should be borne equitably by all market participants. It is not meaningful to hedge against these types of uncertainty.[24]

Market participants would bid for services rendered by others, driven by additional information from the subsystem and system levels.

VIII. Bidding Process for Performance

In the structure we envision, market participants would bid for services rendered by others. This process would involve successive bidding at the market participant (primary) level, driven by additional information from the subsystem and system levels. The market participant would stop bidding when the total cost of tasks 2–5 exceeds the net revenue (after cost of sales) that it can obtain for its power. Participants could change sides, from competing to sell power to supplying tasks 2–5, or vice versa.

The iterative process actually approaches system-wide economic efficiency. Furthermore, the proposal is not difficult to implement, as long as coordinated, nondiscriminatory cost-charging signals are furnished to market participants on a regular basis. The structure is based on present utility practices for management of ancillary generation and functioning of the system. An operator, acting at the coordinating level for strictly technical functions, could evolve into an ISO that accommodates bids for power as well.

IX. Peak-Load Pricing for Transmission and System Services

ISO developers must recognize that the act of pricing signals for system support can be viewed as another dynamic feedback in the system, in addition to technical feedback. Over the long term, which is relevant for dynamic efficiency of the system, optimization for efficiency by ISOs is directly affected by optimizing system support to the otherwise competitive power supply market.

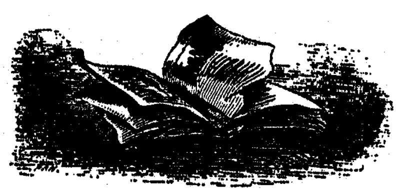
Establishment of system control services is a dynamic, evolving process. Resources dedicated to these services must be committed in advance of need. As conditions vary, the location and amount of projected system control services will vary, too. System support is generally provided by two types of control services: generation-based (for frequency and voltage) and transmission-based (voltage support). The services are qualitatively different because generation-based services could become competitive rather than cost-based, and because they have a significant operating cost (fuel). The transmission-based services sector, however, remains a monopoly, is cost-based, and most costs are attributable to capital.

This dichotomy creates problems. Economic incentives must be developed to enhance the grid instead of just creating generation-based systems services. To avoid inefficiency, an ISO must compare the cost of grid enhancement to that of the use of high-cost generation. Over the long term, it may be more cost-effective to build a FACTS (Flexible AC Transmission System) device than to use high-cost generation to avoid transmission grid congestion.

In assessing the creation of systems control services over long time horizons, one must account for the additional risk involved. But regulators could reduce that risk by clearly defining the responsibilities of the players over long time periods.

Transmission planning must be integrated into the competitive environment. The use of strictly financial instruments,[25] which have been proposed as a means of eliminating transmission congestion, does not lend itself directly to a coordinated establishment of resources such as transmission and generation grid enhancements.

We suggest an idea along the lines of peak load pricing for system services as one possible candidate pricing mechanism of this type.[26] This type of pricing is not foreign to the power industry, although in the past it was used primarily for generation planning.[27] While it is more complex to use this mechanism to value transmission and ancillary services, it is



certainly possible to do so.

X. Conclusion

Regulators could cut through the present circular debates concerning deregulation by quickly introducing performance-based incentives for the creation of ISOs. High technologies, such as computers, communications and real-time controls (3C technologies) are essential for intelligent ISOs. ISOs must begin to learn what the primary market trends are and to project the need for transmission enhancements and provision of adequate ancillary services, so that the number of unserved transactions is minimized.

If regulators are to take this path, they must accurately define areas of active open access, and revisit the performance objectives of both the interconnection and the individual ISOs. The entire NERC Working Group devoted to the Interconnected Operations Services (IOS)[28] is now struggling with this step. Without quantifying the minimal expected performance of individual ISOs, and without penalties for non-performance, the process will be left to the mercy of the better informed.

In this article we have endeavored to describe a possible systematic framework for moving into the direction of an incentive-based system of transmission service. The serious issue remaining is that defining meaningful distributed performance objectives for reliability and efficiency within an interconnection may be an impossible theoretical challenge.

Instead, the interconnected power system under open access could be viewed as a single entity which can best be managed in a coordinated manner. That management could be achieved by employing the high-end technologies used in other industries. One should not forget, however, that these technologies have high costs which the system must evaluate against alternatives.

Reliability and efficiency must be part of the framework of the new electric system from the very beginning or customers will gain nothing from all the turmoil and could even lose ground in terms of degradation of service. Would-be deregulators need to get it right from the start. ■

Endnotes

1. Jonathan Friedland and Benjamin Holden, *Utility Deregulation in Argentina Presages Possible U.S. Upheaval*, WALL STREET JOURNAL, June 19, 1996, at 1.

2. Alfred E. Kahn, Aviation Safety Record Has Improved Since Deregulation (June 21, 1996) (Interview on "Morning Edition," National Public Radio, Segment #3).

3. Robert Davis, *Chief: FAA took too long on Valujet*, USA TODAY, June 25, 1996, at 1.

4. Edward J. Kane, *The Unending Deposit Insurance Mess*, 27 SCIENCE 451 (Oct. 1989).

5. ALEX HENNEY, A STUDY OF THE PRIVATISATION OF THE ELECTRICITY IN ENGLAND & WALES (London EEE Ltd., 1994).

6. John A. Arcate and John B. McCloskey, Telecommunications in Canada (Compian Associates, N. Tarrytown, N.Y., May 1995).

7. A detailed presentation of the analysis can be found in M. Ilić, L. Hyman, E. Allen, R. Cordero and C-N. Yu, *Interconnected System Operations and Expansion Planning in a Changing Industry*, in THE VIRTUAL UTILITY: ACCOUNTING, TECHNOLOGY AND COMPETITIVE ASPECTS OF THE EMERGING INDUSTRY (eds. Shimon Awerbuch and Alistair Preston, Kluwer Academic Publishers, 1996).

8. By "interconnection" we mean an electrically interconnected region, but not necessarily the entire electrically connected grid.

9. Loosely speaking, by dynamic efficiency we mean a process by which most of the investments are made by various market players so that the customer sees benefits of deregulation—for example, the system should recognize that sometimes it may be less expensive to build system enhancement, or invest into a 3C technology, than use expensive generation. This notion can be applied to new investments, but it could also be used to induce effective use of existing resources.

10. In this article often referred to as decentralized decision making.

11. This applies to the system in the United States, as well as to the systems in the European interconnection.

12. Market participant is used here as a generic term, and it ranges from implying an Independent Power Producer (IPP), or individual wholesale customer through representing the aggregated players within an ISO.

13. Referred to as tertiary level in note 16, *infra*.

14. It is critically important to understand that such an organizational form would exclude a scenario by which a power marketer purchases power from one region to sell into the other. In order to allow for meaningful energy trades across vast geographical distances covering more than one reliability region one must envision coordination for reliability and efficiency over a vast area. In principle, this could be done. However, it would require clever technological developments to manage even just the essential information. Decentralized decision making to accommodate such transactions without a coordinating ISO would lead to much gaming, which is potentially dangerous for both reliability and economic efficiency.

15. Utilities are used to meeting their share of responsibility for systemwide reliability. This cannot continue without *enforcing* standards for adequate technical participation.

16. For a comprehensive analysis, see M. Ilić, S.X. Liu, *Hierarchical Power System Control: Its Value in a Changing Industry*, in ADVANCES IN INDUSTRIAL CONTROL (Springer-Verlag London Ltd. Series, May 1996).

17. Only recently have the equivalent of electricity valves (FACTS devices) come into service. *See* Elec. Power Res. Inst. Report TR-100504, March 1992.

18. M. Ilić, F. Graves, L. Fink, and A. DiCaprio, *A Possible Framework for Operation Under Open Access*, ELEC. J., April 1996.

19. Rigorous system theoretical explanations of the need for minimal coordination, including systematic posing of what and how much is absolutely necessary to coordinate, are not the subject of this article. For details on that topic, *see* Ilić et al., *supra*, note 7.

20. *See* M. Ilić, Y.T. Yoon, A. Zobian, and M.E. Paravalos, Comparison of Transmission Cost Allocation Methods of the New England System (Sept. '96) (to be reviewed in IEEE Transactions on Power Systems).

21. This may create some losers, since not all existing equipment will be actively used under open access. This should be dealt with as a genuine regulatory, nontechnical problem; ideas such as cost-shifting among subsystems to avoid losers in transition could be used to minimize the damage in transition. Future investments would not require this regulatory intervention, provided that the system is enhanced to minimize the risk of investment.

22. Note 14, *supra*.

23. It is assumed here that the spot market coordination would be too complex even for a super-ISO.

24. For a multi-level bidding within this framework, see note 16, *supra*.

25. W. Hogan, *Contract Networks for Electric Power Transmission*, J. REG. ECON., Sept. 1992, at 211-42.

26. B. Lecinq and M. Ilić, Peak Load Pricing for Transmission (accepted for presentation at the Hawaiian Systems Conference, Jan. 1997, and submitted for review to the J. Reg. Econ., Aug. 1996.

27. M. CREW AND P. KLEINDORFER, PUBLIC UTILITY ECONOMICS (St. Martin's Press, 1979); S. HUNT, G. SHUTTLEWORTH, COMPETITION AND CHOICE IN ELECTRICITY (J. Wiley, 1996).

28. This effectively covers both transmission path provision and reliable operation.