Harvard Electricity Policy Group
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RAPPORTEUR'S SUMMARY*

Session One: Session One: Siting and Eminent Domain: Is Parochialism Growing? Is It Ripe for Pre-Emption?

There is a growing disjuncture between the siting/licensing of new generation and transmission facilities and the evolution of the electricity marketplace. While markets have regional configurations that correspond little, if at all, to state boundaries, the siting process remains exclusively a state function. The disjuncture is further complicated by the fact that need determinations, a prerequisite for approval, are often defined, by statute and/or by judicial interpretation, in terms of monopoly service and local (i.e. in-state), not regional, requirements. Recent decisions by courts and siting agencies in Massachusetts, Florida, and Connecticut are examples of how siting laws are interpreted in ways that impede market development and put parochial requirements above regional ones. Has the time come for the Federal government to pre-empt the field? If so, what should be the nature of the pre-emption? Are regional institutions, joint boards, and other cooperative mechanisms preferable to complete pre-emption? Should FERC determine need and let the state conduct the environmental review within certain time and cost constraints? What is the appropriate balance to be achieved in weighing regional market needs and local environmental effects? How does one define need in a competitive marketplace? Should eminent domain flow from status as a utility or, rather, be derived from having obtained siting approval? What is the relationship between the siting process and the evolution/operation of RTOs? How do siting processes and eminent domain powers impact the evolution of competition? Are there winners and losers, or are all parties appropriately balanced?

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* HEPG sessions are "off the record." The Rapporteur's Summary captures the ideas of the session without identifying the speakers.

Speaker One

Is there a place for a Federal role in transmission siting? And a similar argument would apply to the siting of generating facilities. When we started, the holy trinity of issues was pricing, access and siting. Pricing is being seriously addressed and in some cases appears to be settled. Access was resolved through a combination of the Energy Policy Act of '92 and Order 888. What have we done on siting? Nothing. It's the one issue that everyone thinks is important but that simply has gone unaddressed, at least at the national level.

What is the current situation on siting in terms of legal jurisdiction? There is very limited Federal authority. What Federal authority there is, is related to Federal lands, to crossing navigable streams, and it's scattered as to what agency even has jurisdiction. FERC has almost no jurisdiction. State powers, at least in theory, are plenary with the state government, except that 22 states have exercised no jurisdiction over it. Twenty-eight states have siting statutes.

The companion issue to siting is eminent domain. Again, there is very limited Federal eminent domain. The majority position in the states is that eminent domain is exercised by those who have legal status as registered utilities within the state. The minority position, and it's a very small minority of states, is that it doesn't matter who you are. If you obtain approval from the siting agency, eminent domain comes with that approval. It skews the competitive process because in most states, if you're a utility, you can use the powers of eminent domain to site a facility. And only in the minority states can anyone have access to the same powers.

What was the purpose of state siting laws? There were three. One was to preempt local powers and take out of the equation those parochial interests represented by local government. It became clear that if you had to go to every local zoning board to get a power line or generating facility approved, you were in trouble. It couldn't get done in any practical sense. The second purpose was to allow one-stop shopping with different agencies. The final purpose was to create a coherent and transparent decisionmaking process with the opportunity for formalized input by the public.

These jurisdictional arrangements are really a historic accident. Electric utilities grew up as local entities. They were monopolies. They tended to be vertically integrated. So it made sense for jurisdiction to remain at the state or local level rather than Federal. Reliability and trading became expanded uses of it. Most states, because it was in their self-interest, incorporated a lot of reliability considerations into whether or not they'd approve siting or allow eminent domain to be exercised. Large-scale trading is even more recent. That really has not impacted yet on the siting process. The monopoly status of utilities played a role in that we didn't raise a lot of questions, particularly about who had the power of eminent domain. And most states have, for good reasons, a reluctance to allow private parties to use the power of the state to condemn property.

What's the nature of the process? Generally, one, you have to establish the need for the facility. Two, the state blesses the prudence of the utility's planning process, which in the old monopoly days meant you were exposing the ratepayers to enormous costs passed on through the rates. Approval is because demand is such that the facility is necessary and essential. Once you establish need, you go to non-economic review factors--environmental, health, aesthetics, etc. That goes into deciding whether the facility can be built in a reasonably benign way from an environmental health, etc. point of view, and the route that best accomplishes that objective. So it's a two-fold process--to establish need, and to look at the non-economic factors and come up with a process by which the facility gets routed.

What about the definition of need? In the context of a monopoly, defining need was not complicated. You looked at their demand projections and asked whether they were reasonable. What constitutes need in a competitive market? It's not clear. One could argue it's anything that contributes to a competitive market, as long as ratepayers aren't obligated *per se* to pay for it--then you build it, obviously still subject to the same environmental and other non-economic review. Most states have not addressed this.

Then we have to look at the context of need. One context is exemplified by the *Tampa Electric v. Joe Garcia, et al.* case, in which the Florida Supreme Court said that to show need you have to have 100 percent of the output of the plant committed to a jurisdictional Florida utility. I've never seen a better articulated defense of monopoly power; the combination of the decision and statute says competitors are not allowed into Florida unless they sell through a Florida utility.

A second case is the recent decision by the Siting Council in Connecticut on TransEnergie's application to build a DC line across Long Island Sound. The board said, We see real benefits for this line in Long Island or within the region, but we don't see any particular benefits for Connecticut. Therefore you don't meet the need definition. Think about the implications of that: The region shouldn't get any benefit out of the line--though they acknowledge that there is a real benefit for the region--and the benefits out of state are less important than the in-state benefits. Little heed is paid to the fact that the line arguably enhances the competitive nature of the market within the region and in Connecticut.

Another case is *Point of Pines Beach Association v. The Energy Facilities Siting Board*, in which the Massachusetts Supreme Court said that the relevant need was the need of the residents of Massachusetts. They went on to opine that the mere existence of a Power Purchase Agreement is not sufficient to establish need; in fact, you have to show that market-driven demand is driving the need for the facility, i.e., the forecast of demand as opposed to a contract. Afterwards, everyone saw this as bad law, and there were attempts to amend state law. But some of the local utilities started thinking that making it easier to site would mean competition, and that's bad. And Massachusetts hasn't done a thing; this still stands.

The final case, *Mississippi Power & Light v. Louis A. Conerly et al*, is from the Mississippi Supreme Court. The court said the utility couldn't exercise eminent domain because it couldn't show that Mississippi citizens got the benefit from it; the benefits appeared to go out of state. That didn't preclude them from siting the facility, but it certainly drove up the price of siting it, assuming they could acquire the land without use of eminent domain.

Let's look at what has been a parochial response by a number of states, or reinforcement of parochialism. Only a tiny minority of states, I think two, explicitly by statute require the siting agency to think about what's going on in neighboring states. In the rest of the states, the siting agencies are free to ignore that. Twenty-two states have no coherent siting regime, often allowing local interests to block it, or you don't get effective environmental or health review because the utility has enough power to site the facility regardless of other considerations. Benefits are viewed primarily in terms of intrastate needs.

What are the dynamics of this regime? One, it discourages investors from seeking approval of facilities that cross multiple states. There are a number of these cases. For example, there was an effort in the late '70s-early '80s to build a line from Manitoba to Nebraska that was stalled by one of the Dakotas because they thought they wouldn't benefit. It's the same with discussions over the years about lines between the Midwest and Northeast; Pennsylvania's made it clear that unless they get real benefits out of it, they're not interested in siting the line. Two, there's nothing that acknowledges the fact that the market has fundamentally changed and that our determination of what's needed in terms of generation or transmission is quite different in a competitive market. Three, this regime skews resource allocations in a direction of least resistance rather than economic optimization. Wherever resistance is least, that's where you site. And as I've pointed out in the Florida case, this provides an effective tool for monopolies to impede and perhaps preclude competition from coming into the marketplace.

What are the conclusions? One, it's difficult as a public policy matter to justify the states playing the exclusive role in siting facilities that have multi-state implications. I'm not saying that the state has no role to play. But the state having sole jurisdiction is a relic of the past that can't be justified. Two, the need determination must be made by an entity with a national or regional perspective. Three, multi-state facilities ought to be entitled to the same exercise of eminent domain powers as are intrastate. I'm not suggesting that we should suddenly become more liberal in allowing private parties to use powers of condemnation. But I am suggesting that the part of the siting process in which there is a role for the Federal government ought to include the ability to obtain eminent domain. Otherwise the competitive balance and the costs are skewed in favor of existing utilities and opposed to new entrants or investors.

What are the options? One is total Federal preemption. Then you have to define what Federal agencies you're speaking of, since even within the limited Federal jurisdiction, it's diffused. Politically, this is not an option that's likely. The second option is a regional mechanism or joint board approach where states are allowed to exercise siting jurisdiction and eminent domain powers, but have to do it in a regional compact with other states so that a regional perspective is forced into the process. The third option is to bifurcate the process: FERC determines need in the context of the regional multi-state market, then, within time and cost constraints, defers to the states on the routing of the facility. The states have to decide by a certain date and can't arbitrarily cause the cost to escalate to the point that the facility can't be sited.

Comment: The Massachusetts law has been changed from showing need to enhancing reliability.

Speaker Two

I'd like to offer a possible framework for a Federal role in this process.

What kind of objectives are necessary to this certification process? There is a crisis in investment in the transmission business, so one objective is to promote beneficial investments in transmission infrastructure. Another is to promote certain technologies. When people think transmission, they think overhead towers, large rights of way through virgin forests, etc.; it's important to realize there are other choices. Competition in interstate electricity markets is a goal. Consideration of regional benefits in this process is another. An important objective is to ensure that eminent domain is granted in a judicious manner, only to projects that truly qualify, and once granted, it should be done with care. A final objective is to rely on a framework that we already have, which is the certification process of interstate natural gas pipelines. Siting a generating facility in a downtown area is a lot easier than bringing a transmission line into that downtown area. But gas pipelines, transmission and generation are all in direct competition.

In trying to frame this process, I've come up with four criteria that I suggest should be required for any project wishing to follow a Federal certification process. First, there should be clear FERC jurisdiction in terms of rates, terms and conditions of service. Second, the purpose of the project should be to increase interstate or international transmission capacity. Third, physical service under the facility should be provided by an RTO. Fourth is probably the most controversial--that this process be limited to projects that do not rely on overhead transmission lines as an integral part of the project. This doesn't exclude all overhead projects; if you needed a short piece of overhead wire as part of an interconnection facility in a substation and the rest of the project is primarily underground, that shouldn't disqualify the project.

Why FERC jurisdiction? It's an open access issue. There should be a role in ensuring that capacity on the facility is available on a secondary market basis. And this ensures a role over the prices for such capacity. It could be a cost-based, market-based, or other kind of framework. But it ensures a role for FERC in protecting captive ratepayers.

The second criteria is that the project increases interstate and/or international transmission capacity. I think this is consistent with the role of the Federal government in interstate commerce, and it ensures you have somebody looking at things from a more global perspective.

The RTO requirement is one where physical service would be provided pursuant to an RTO tariff. Everything that has to do with the physical operation of the facility should be done pursuant to an RTO tariff approved by FERC. Also, any transmission rights created by the project should be pursuant to a FERC-approved tariff and market rules, whether financial or physical. This also ensures that the various technical requirements of an RTO are met, interconnection, operational standards.

Finally, no new overhead transmission lines. We're using fiscal policy to encourage low-impact technologies. I see this as a *quid pro quo*; we will give you the police powers of the state, but in return, it needs to be done in an environmentally conscious manner. This also maximizes the use of existing rights of way and encourages the development of technologies that fully utilize an existing right of way.

The process I propose generally parallels that for interstate gas pipeline certificates and generally focuses on the determination of need on a regional or national basis. I've also thrown in a 12-month maximum time frame. A possible standard of review is a balancing test, to look at the public benefits versus the potential adverse consequences of the facility. From the benefits perspective, I'd like to see a consideration of regional issues, but also a real focus on what's the burden of this facility on captive ratepayers. On the adverse consequences, we have a myriad from environmental to utilization of capacity.

I see two parts to this process. First, a determination of public need would be made, taking into account issues such as demand for the project, reliability benefits, competition benefits of the facility. The second portion of the process I'll call the Environmental Policy Act Review, which consists of either an environmental assessment which is relatively short process or a full-blown environmental impact statement. Upon completion of this EA or EIS, you would get a certificate.

What would be the role of states and other local interests in this process? Full participation as an intervener in the process, and input on route issues, need, benefits and possible impacts of the facility. Again, this is similar to what is in place for the natural gas industry. FERC has traditionally made a good faith effort to defer to state concerns in the siting of pipelines. So you will still have to go through a state siting process, but the permits need to be consistent with the conditions granted at the Federal level. Eminent domain authority would go with this certificate, but should be done with caution and judiciously.

It's working on the gas side; there is increasing investment and throughput.

Speaker Three

The typical state siting council was created and continues to have three main roles. One, to streamline development via the one-stop shopping method. Two, to coordinate state and local functions and, only where necessary--e.g., for multi-jurisdictional facilities--to preempt local ordinances. And three, to monitor supply and demand balance to ensure that there is no overbuilding of facilities.

The job of the state siting authority is basically to balance benefits, i.e. need, against cost, environmental impacts. Rather than a bifurcated proceeding where first you look at need and then at environmental impacts, those two functions take place in tandem.

Under the traditional model, until about five years ago, the siting authority's job was fairly straightforward. First, the benefits of the facility were reaped by the same general population as those that bore its environmental costs. So in performing its balancing act, the siting authority didn't have to benefit one population at the cost of another. Second, need would largely be determined by a state regulatory authority or, in some cases, a publicly owned utility. The siting regulator didn't have to worry about determining need independently from the utility regulator. And third, the environmental costs were largely determined by the state's environmental regulators or, in some cases, by local environmental agencies.

In the late 1990s, this got turned on its head, making siting decisions much more complex. First, the impacts of a facility are no longer necessarily borne by the population that reaps its benefits. For example, Whatcom County in Northern Washington, mirroring Washington as a whole, has an industrial populated area to the West and a rural agricultural population in the East. The county has two natural gas pipelines coming from Canada and into Washington State and California, oil refineries on the coast, several large combustion turbines located mostly on the coast, and a couple of combustion turbines proposed to be located in rural areas. Despite the fact that the county is extraordinarily dependent on the energy industry for an industrial and economic base, it has never overtly or comprehensively acknowledged or analyzed the importance of energy transmission, production and consumption to its economy. Hence it's not well prepared to respond when new proposals come in. Siting decisions are scattered among local regulators, the state siting council, and Federal regulators, with no overall review of the cumulative impacts to the county and its neighbors.

This illustrates the imbalance between benefiting populations and those bearing the costs. In many cases, a local population, particularly if it's rural or depressed, will support the development of a new power plant or energy facility because of the tax base it will bring to the community. And in our restructured wholesale environment, the regional market also benefits from new energy facilities which are supposed to drive down market prices, although we don't always see that in the West.

The population that doesn't see a lot of the benefits of the facility but bears all the environmental costs, I call "donuts". In this case, the state siting council may insert itself into the process to protect the donut population, or at least ensure that its views get heard.

Finally, when the proposed facility is a fossil fuel plant, there is another potentially disenfranchised population: All of us, since we all bear the impact of increasing levels of greenhouse gasses. Because the contribution of greenhouse gasses from thermal plants is so important, it is impossible and unethical to ignore. Yet only one state, Oregon, has directed its siting agency to set standards for C02 reduction.

A second way in which siting has become increasingly complex is that the utility regulator can no longer be relied on to make determinations of need on behalf of the siting authority. Regulators are dispensing with their IRP requirements by saying that the regional market will determine whether a plant is needed. This places the siting authority in a dilemma because we no longer have adequate information about whether the benefits of additional capacity are worth the environmental cost. And this situation is exacerbated by local land use regulators' understandable desire to ensure that local land uses are consistent with local welfare. The siting authority is told by local residents or the donuts that there's no reason to site the plant here; we have better uses for our land.

So state siting authorities are faced with an increasingly complex job, and most states have not taken a close look at siting statutes to ensure the tools needed to accommodate this changing world. I hope governors will not address the issue by abolishing siting laws or providing categorical exemptions without careful consideration of the impact of such moves on the affected populations I've been talking about. Given the continuing need for access to affordable energy supplies combined with huge environmental impacts of most cost-effective energy resources, there's still an important role for state regulation of energy facility siting.

A central question is whether the Federal government ought to preempt states in siting new energy facilities. I would caution against such an approach, at least in a comprehensive way. First, the Federal government has not exhibited stellar competence in its safety oversight of energy facilities. You may recall the oil pipeline explosion in Bellingham, located in Watcom County, where three people died. Lax Federal oversight of pipeline safety was been cited as one of the main contributing factors.

Second, environmental justice is difficult to achieve when one is 3,000 miles away from affected populations. There's a temptation to pick the location for its economic siting value, ignoring local impacts. Our state and local regulators have been continually offended by FERC's cavalier attitude towards local and state concerns in siting new natural gas pipelines. For example, public hearings are routinely held on only one or two days' notice.

Third, Federal regulators will not have all the tools needed to identify or implement more cost-effective alternatives to building new energy facilities, such as load management or distributed generation to relieve transmission constraints. In a model where FERC decides the need for the facility and then the local regulators just decide routing, it may be difficult for the local regulators to say, well, maybe you don't need a transmission facility at all.

On the other hand, if states want to resist having the Federal government take over siting, they need to demonstrate that they can cooperate regionally, make sound siting decisions and not hamper the development of a competitive market. Here are some possible approaches.

First, one could substitute for a need requirement prescriptive approaches that recognize the unique characteristics of energy. For example, the Oregon Siting Council changed its statute several years ago to recognize different siting standards depending on the kind of facilities being sited, including a C02 standard for fossil-fired plants. Rather than looking at need, one would look at the environmental or other impacts of the facility and possible ways of mitigating that. Second, one could set energy prices that incorporate all environmental externalities. This could, for example, be done through RTO prices. Third, one could have regional planning with strong provisions for local involvement. These three approaches are not exclusive of each other.

Under this last approach, transmission constraints could be identified by a regional body and new transmission or generation could be built at locations that make most sense regionally. A regional body would agree on consistent regional goals, an example being the Northwest Power Planning Council. There would be strong local involvement, with preemption being the last resort, recognizing the environmental concerns of the donuts.

I don't think state regulators are becoming more parochial, but the market is becoming more regional, which requires different approaches. State siting regulators need to be much more flexible and recognize the regional benefits of new energy facilities. A balanced response would be to acknowledge the need for regional cooperation and set regional energy goals that reflect both the need for energy facilities and their environmental impacts.

This is something I heard somebody say on NPR last week. Federal lawmakers need to act in concert with state and local governments, which usually have a grasp of the problem and what is needed to solve it. Washington has sometimes relied too much on threats and mandates from afar when it should be encouraging innovation and high standards in the people closest to the land.

Discussion

Question: Can you expand on the science of putting wire in the ground, especially re: the political perception versus the reality of putting spark next to gas?

Answer: There needs to be a significant buffer. But the insulation and grounding techniques available now greatly minimize that effort. It is a sensitive issue, and I suggest starting an outreach process as early as possible, talking to community members and anybody who's willing to listen to you about the benefits, safety considerations and possible impacts of your facility.

Comment: There are a couple of other elements that need to be fixed in terms of development in the wholesale market structure and efficiency, and lack of Federal eminent domain. Two examples. One of the consequences of the Duke Smyrna decision in Florida is that we're seeing lots of peaker plants being built. But one of the holes in the law is you can build plants that don't use steam, so people are building a lot of those whether they're needed or not. The other hole in the law was you could build with steam if you were less than 80 MW, so some combined cycles are being either purposely misdesigned or are just inefficient. Two, in Virginia the deregulation law will do away with eminent domain for the utility to "create a level playing field." But the utility is proposing transferring its assets to an affiliate. So the level playing field begins with a concentration of highly developed site potential.

Response: The Florida case does stand for the proposition that all these things have a competitive impact. Clearly the siting laws are used by some competitors to keep other competitors out of the market. On the other issue, the reason for the minimal size requirement exceptions were, well, how big could the environmental impact be since the economies of scale aren't that great anyway, so why put them through all these transaction costs. This is one of the reasons there needs to be a role for FERC, which will be thinking about competition and how it relates to this. Most siting laws are not administered by the utility regulatory agency, so no one is looking at the competitive impact of this.

Question: There needs to be a sharper distinction drawn between the processes used for generation and for transmission siting. They still are different, though as transmission becomes a more commercialized activity maybe that distinction will begin to go away. More broadly, the U.S. is a free trade area, so why is the siting of an energy facility in one state that primarily or even entirely benefits consumers in other states not regarded simply as another export activity? The regulatory process involved in regulating these lines may restrict the various parties' abilities to share benefits.

First Response: There have been states that have thought about it that way, most notably West Virginia. But you can't because you build an energy farm with no ability to get your product to the marketplace. Maybe the answer lies in the way FERC regulates transmission pricing.

Second Response: Both applicants for building new facilities and regulators are taking a too narrow approach to demonstrating need in the first place. There are abundant ways for a merchant facility to demonstrate the benefits of building a new power plant, like showing the increased benefits of reliability and regional cooperation.

Question: The California ISO has been approached on numerous occasions by companies advocating use of new technologies for transmission systems. Some issues arose about increasing numbers of participating transmission owners coming onto the system, and the issue of a right of first refusal for the local transmission owners, i.e., whether they would have an opportunity to say, We'll build, invest in those facilities. Has this issue come up?

Response: In the protocol originally submitted as part of the nodal pricing system for New England, there was a right of first refusal included. FERC struck it down and removed it from the transmission expansion framework in New England. GridSouth also included such a provision, and again the Commission struck that down.

Question: Can you elaborate on the two-part process you described?

Response: The model of the Northwest Power Planning Council, an IRP model, identifies need in the simplest sense of what's demand going to be, then identifies options to meet it. That is what a number of regulators hope will work with the RTOs in that you not only look at need, but identify a number of alternatives and then undergo an iterative model to determine which not only has the least direct cost but also the least external cost. The approach has to be iterative and not sequential, and works best in the context of an RTO or regional planning organization.

Question: I've encountered utilities that own congestion rights or contracts whose value is predicated on a certain level of congestion on the system. If they allow investments on the grid that reduce congestion, they lose out financially. So why not do away with eminent domain altogether for certain types of new technologies that do not require it, i.e., make a bargain where facilities that have low environmental impact and controllable power flows can be sited without recourse to eminent domain, provided they are afforded unregulated rates?

Response: A lot of those facilities don't need eminent domain because you're talking about co-locating with existing rights of way. But there is another issue: What changes in the use of the right of way trigger a requirement for a new siting process? I don't know the answer, but it would be valuable to have a uniform answer across the states.

Comment: The environmental community is convinced that some type of IRP process is essential, a regional process that looks at all the options, done by an entity with independence from market participants and the resources with which to do the sophisticated analytical work to look at all the economic factors. Would this move us toward the kinds of decisions in which investments will be forthcoming? My only model at this point is the PJM transmission planning process, where a lot of that analytical work is done and then the competitors are invited to make proposals which are then evaluated.

First Response: I agree we need an independent entity, but I would rather see a system where locational prices deliver true signals so that any investment has an opportunity to capitalize.

Second Response: Neither extreme works. You don't want to screw up the market with some arbitrary administrative decision. But there are economic externalities that rarely if ever get reflected in the pricing. So how do we deal with those kinds of questions? What's clear is that the existing institutional arrangements help to protect existing monopolies. There has to be some sort of coherent arrangement between getting the correct pricing and dealing with these externalities in a way that makes sense.

Third Response: Perhaps the best approach is to get pricing as close as possible, then use IRP to fill in the gaps. IRP can identify options and generally identify need without identifying specific facilities in specific places.

Question: Where does FERC stand?

Response: With FERC's gas policy, pricing is still an issue. The Commission, in the certificate area, still hasn't fully implemented the idea that these lines shouldn't have subsidies. The important issue is balancing takings versus greater efficiency, i.e., greater public benefit, including environmental issues as takings because you're taking environmental benefits away from people. On eminent domain, I suggest looking at the percentage of property rights already acquired under option on the right of way. That way, you can argue if you have 80%, the remaining 20% may be justifiably exercised.

Question: I understand that at the Western Governors Association meeting, a task force was formed to identify where transmission needed to be sited and then take action. What were the results?

Response: That is moving forward. The first report is to be put together in late summer. For the second stage of the process, the governors will look at pricing. Also, the National Governors Association is putting together a study on this.

Session Two: Excess Capacity or Capacity Excesses?

Electricity supply shortages have shocked the nation and raised serious questions about market restructuring. When there is excess generating capacity, the strain on alternative market designs is modest. But when there is scarcity, even minor market flaws can be severely magnified. It is clear that the cost of too much or too little generating capacity can be serious, but there is a case to be made that the errors of shortage are greater, much greater, than the errors of surplus. In theory, the market may provide the signals for capacity investment. In practice, the intervention of regulation may be a requirement. The crisis in California exists in a state without a regulated mandate for capacity investment. Even in New York, where such a regulatory requirement exists, a state agency took on the emergency task of installing new capacity in New York City. The installed capacity markets of New York, New England and PJM may be seen as more important in light of recent experience. How are these markets structured? What is the evidence about need? What has been the performance of capacity requirements and markets? What are the best ideas for acquiring a cushion of "excess" capacity without creating capacity excesses?

Speaker One

I'd like to talk about the evolution of the capacity markets and how they're working in PJM.

Prior to wholesale competition, PJM was a power pool. Its eight member utilities each had a capacity requirement, in addition to which the state PUCs required individual utilities to plan for capacity. The combination resulted in high levels of reliability. If you didn't have capacity adequate to meet your peak load, you were required to pay a rate which was an estimate of the cost to build up peaker in PJM. It worked as a mechanism to spread out the lumpiness of capacity additions. Ultimately, a nontransparent market evolved in capacity credits.

In late 1998, when Pennsylvania instituted retail choice, there was interest from the Pennsylvania PUC in having a transparent capacity market, so PJM implemented a daily capacity market on January 1, 1999. The energy market was introduced sometime thereafter. Bear in mind that the ISO remains responsible for reliability, so reliability is an aggregate concept. PJM's target is a one-day outage in 10 years, which is industry standard.

Basics of the capacity market in PJM: Load-serving entities are required to have rights to capacity. You can obtain those by owning capacity, by purchasing rights to capacity bilaterally, or by purchasing capacity credits in PJM capacity credit markets. The kind of capacity of this purchase we call unforced capacity, which is installed capacity derated for historical forced outages. Active load management is also a capacity resource and directly offsets LSEs' capacity obligations.

It's frequently alleged that capacity is a phantom product. I would argue that that's not the case in PJM. You're buying and selling a couple of things with capacity. The first is that you're buying recall rights to the energy from capacity resources during an emergency in PJM, defined as where expected load is greater than the total of all economic offers into PJM and the real-time market. In addition, capacity resources are required to be offered into the day-ahead market. One flaw is that there is no availability requirement other than the forced outage limit. The unforced adjustment is a limited incentive. There's also a transmission-related deliverability requirement. Finally, there are no limitations on selling the energy from a capacity resource off system other than the recall rate identified.

PJM runs a number of different capacity credit markets--daily, monthly, multi-monthly. If you are a LSE who tried to buy capacity and can't because you've offered too low a price or there isn't enough, you pay a penalty, which is an estimate of the cost to build a peaker in PJM. Capacity can be sold within or outside of PJM. The actual out-of-pocket marginal cost of capacity is probably zero in most circumstances, but there are real opportunity costs. The best alternative to selling capacity inside PJM is to sell firm liquidated damages energy outside of PJM. And it's possible to compare the revenue stream from the two options.

There are a number of benefits from having a capacity market. One is reliability. In fact, in the hot spell in summer 1999, with 15 days of emergencies in PJM, PJM recalled some or all of the energy associated with capacity resources. There is some incentive to buy low outage rates. In addition, capacity markets can provide an incentive or at least part of the incentive to build new capacity. PJM's capacity queue is in excess of 40,000 MW.

Some of the impacts of capacity markets are not well understood. The existence of a capacity market doesn't necessarily and in general does not change the energy market dynamics under non-emergency conditions. Capacity can delist, can sell its energy to the area of highest price. Existence of a capacity market also does not necessarily change the probability of scarcity in real time, scarcity being the relationship between PJM load and economic offers to provide energy inside PJM. The existence of the capacity market does change the duration of scarcity. When prices rise and PJM is in an emergency situation, it can recall the energy and therefore limit the duration of the scarcity and thus high prices.

There are many issues associated with the capacity market, not the least of which is market power and associated market design issues. While you may think demand for energy is elastic, demand for capacity is inelastic. It's defined by a planning process inside PJM looking at loss of load probability; in aggregate, that amount is fixed during a year and not sensitive to price. Incentives are a function of one's load obligations and whether or not you're an integrated utility.

Market design issues include how to structure the market so that a rational economic incentive exists to leave your energy and capacity in the system. Right now, the incentives are to sell; that's a result of not having an availability criteria and an explicit availability incentive built into the market. There are a couple of variations of call options--available capacity and call options.

A capacity market does not guarantee reliability. Capacity demand, as we saw last summer, can exceed supply at the market clearing price. The result is scarcity of capacity on high demand days. The simple payment of penalties by LSEs after the fact has nothing to do with reliability; it's simply an incentive for them to bid a reasonable price into the market. Good market design is required.

Recent results in PJM. For summer 2000, there were significant exports of capacity, and available capacity inside PJM fell below the obligation as a result of an incentive problem in the way the market is designed. capacity prices looked like. Capacity prices spiked in the summer of 2000, as well as earlier in the year due to incentive problems and the use of rules to exert market power. Forced outage rates are down in PJM since the introduction of wholesale competition. One of the arguments about capacity markets is they're a form of additional revenue. In 1999, from the energy market alone PJM had enough contribution to cover in round numbers the fixed cost of a peaker. Not so in 2000, but it does when you add capacity market and ancillary service market revenues.

Speaker Two

Back in the mid-1990s, I was telling people that installed capacity requirements had no useful place in a competitive electricity market. In real time, people want to buy real power, reactive power, regulation service--but nobody is going to pay for installed capacity that is not doing one of those things real time.

But California is the real world, and the experience in California this past year has convinced me that one assumption is incorrect: That when a power shortage occurs, parties that are resource-deficient will bear the full costs of their own deficiencies in the form of paying high spot prices or having their loads curtailed. In California, price caps in combination with other elements of market design have been used to have market participants with adequate resources subsidize the resource deficits of those who don't. When blackouts occur, LSEs with enough resources to cover their own customers' loads are having their loads curtailed along with the loads of those entities that do not. These things have bad incentive effects on making capacity investments. So an ICAP requirement might make sense to assure that these shortage conditions don't happen.

An installed capacity requirement is basically this. Each LSE is required to have a capacity equal to some percentage of their load, and must pay penalties if they don't have enough.

But parts of this are not so easy to define. What is capacity? It has higher value in some places than in others. If you have a rule that says we will accept as legitimate capacity only that which is available over 70% of the time, then you are making a black and white distinction where you ought to have shades of gray. What is load? Annual, monthly, seasonal, last year's or this year's? If, for example, your load obligation depends upon this coming summer’s load and you don’t know what your peak load is yet, you will have to guess.

Finally, there’s the issue of penalties. If you don’t have penalties, nobody will bother thinking about this requirement. If you’ve got penalties that are $100 per MWh, as PJM had, then people will ignore the capacity requirement when you want that capacity most, mainly when the market prices are high and conditions are tight.

The fundamental problem with the capacity requirement continues to be that the value of the services provided by capacity varies over time, and it’s hard to define the capacity requirement in a way that reflects that. Still, the capacity requirement promises to increase the amount of capacity available to the market. The effect of having that extra capacity is to help stabilize wholesale prices and to reduce wholesale prices because you will have more supply, especially during the peak periods.

It will also tend to increase retail prices because you recover the costs of the installed capacity from your peak retail loads. The market will tend to assign to each MW of retail load that X percent cost of each increment of capacity. So a 1 MW increase in retail load means you’re going to need, if that X percent is 1.18, an extra 1.18 MW of installed capacity. That will tend to drive a wedge between wholesale prices and retail prices that are adequate to cover that extra cost.

I would like to suggest one other possible mechanism that might be similar to the ICAP requirement in the sense of increasing the amount of capacity available to the market and helping to stabilize market prices. That is to arbitrarily increase the real time requirements for what are called either called back-up reserves or replacement reserves so that you are increasing the spot market prices received by generators real time and in a way that reflects the spot market value. Increasing spot market prices will increase incentives to invest, and by increasing it on replacement reserves rather than on the other services, energy, spinning and supplemental reserves, you will not distort those markets that are primarily responsible for assuring balance each hour.

A problem with increasing the backup reserve requirement is that it has to be done in a way that does not artificially increase shortages at those times when the market has shortages. So that requirement has to be price-sensitive so that the effect of that requirement is mainly to raise the market value of electricity in those hours that are near peak.

Speaker Three

During the last years I’ve been involved in discussions concerning security of supply in Latin America, Spain, and other countries. One approach is administrative capacity payments, which was implemented first in Chile and Argentina, now Spain, and which has a number of problems.

We faced several questions. To what extent could the market provide for generation reliability and adequacy? Who has ultimate responsibility for the reliability of supply and generation adequacy? We identified the market failures that would advise not to leave this issue entirely to the market. Like price caps, that would mean insufficient revenues from the market, particularly for the peaking units, leading to uncertainty and risk aversion of potential generation investors. Passivity of demand leads to a small chance of contracting for these groups.

More issues are: Is the price of the spot market enough to encourage operation strategies that provide acceptable security? Should consumers be allowed to choose the level of reliability they want? And if intervention will take place, how can it be designed to least interfere with efficient market operation?

The options explored were, first, no intervention. But our approach was to do something. The second was additional payment to promote some extra guarantee of supply. This is the approach that is used in Argentina, Colombia, and Spain, where a certain amount of money is put on the table to promote investment and to stabilize the volatile income of the generating units. This would in theory encourage generation units to be available to enter into the system.

This has a number of shortcomings. When you have a mixture, particularly a mixture of hydro and thermal units, it is difficult to determine how much to pay to each of them because determination of firm capacity is a difficult issue. And the incentive in the short term for the units to be available when a crisis comes is not there because they are paid every day or hour a small amount of money, and only if they are not available are they not paid that money. There is no good definition of a commercial product that the generators have to deliver in return for the money they receive.

The third option is the capacity markets. PJM is the best example of this. The difficulty, at least in a hydrothermal system, is that somebody has to administratively determine how much is the firm capacity that each unit is going to provide when you have to sign capacity payments. That has been a terrible problem in the countries I've been involved in. How do you compare a 300 MW hydro unit with a 300 MW thermal unit? And there is lack of incentive when a crisis comes.

The fourth approach is, in an ideal market, customers hedge price risk when a shortage occurs and generators hedge revenues risk. But experience says that demand is very passive and that is not an approach you can rely on, so the reason for this reliability contracts approach was to try to overcome these problems.

The case of Colombia is difficult because they have a history of power shortages. It is an irregular system with a lot of hydro production. El Nino happens more or less every five years with severe drought, so the market is very volatile for generators. The system they have now is administratively determined capacity payments. They don't rely on this for short-term security of supply, so have to complement it with mandatory medium reservoir levels, which interfere with the market.

This is the reliability contracts approach. The regulatory authority, through the system operator, would act on behalf of all demand and specify the desired generation adequacy level. Then consumers would obtain a well-defined commercial product in return for their money, with three features: Adequate installed capacity, because it will be mandatory; plant availability at the time it is needed--this is no guarantee, but there are strong incentives; and a reasonable price cap whenever shortages occur. Generators would stabilize the most volatile fraction of their revenues. A market mechanism, an auction, would be used to determine the price to be paid to the committed capacity, and each generator will determine how much capacity they want to commit.

The regulator then requires the system operator to run an auction to purchase from generators a certain amount of reliability contracts (Q) on behalf of all demand. A generator with an annual reliability contract will receive a premium fee and will have to return the amount Q (spot price p - strike price s) whenever p is greater than s.

The regulator specifies the main parameters of the auction--Q, the time horizon, etc. No speculators, only physical generators can bid. The price cap can be set very high. The generators are required to give economic guarantees; they don't need to be very high. Operating (hydro) restrictions can be eliminated.

Other issues are whether the commitments can be transferred to other generators. We decided no, again to make them feel the pressure of the commitment to be available when the crisis comes. There will be some interference with energy contracts, which must be between 0 and S. Market power is always an issue, and there are a few possible approaches. Transmission effects are an issue if active systematic congestion is expected--they would run zonal auctions.

Strong points of the approach are: No need to evaluate firm capacity administratively. Reliability payments are determined by the market. There is a clear commitment for generators to be available when needed. And consumers are protected from the highest spot prices. Weak points: Demand is passive. There is potential for market power abuse. It may not be enough to incentivize new entrants. And potential volatility of auction results.

Speaker Four

In the abstract, you don't need capacity markets. We'd have clearing markets, they would show shortages, shortage of scarcity rents would attract new entrants, new entrants would satisfy our requirements.

Unfortunately, it doesn't work that way for a variety of reasons. We have market failures and regulatory and political limitations that make it an impractical solution. There are concerns about physical adequacy and reliability, short-term volatility and energy price caps, and the interaction of the two, and about the long-term business cycle.

Why is physical adequacy a driver? We have traditional regulatory concerns that have to be satisfied. This is complemented by risk aversion and underlying distrust of markets. And political deniability, which is now in vogue: Problems in the design of the PJM market jeopardized physical reliability, and when you tried to motivate regulators to help find solutions, one of the responses you got was, It's okay, we have a capacity market.

Short-term volatility. We plan markets for shortage; nobody plans a market for 100% reliability all the time. Coupled with inelastic demand, it's a situation where supply can ask anything it wants. That's an unacceptable result politically, and leads to price caps. This is "okay" if we agree in advance to what the price will be during the shortage. In advance is key. And then we create other mechanisms to capture market-clearing revenues. Part of that could be capacity payments or other ancillary service payments.

Politically it's not tolerable to go through a business cycle with volatile prices, so the question is what to do. People want to see hard iron in the ground. They want to know that there is some form of incentives or rules that says, not only do we have that iron in the ground, but it’s going to produce when we need it. And people want the ability to attract new investment for long-term adequacy.

Basic functions of an adequacy market: Establish a reliability criteria. Establish a reserve/installed requirement. Assign requirements, who picks up what based on their loads. Establish eligibility and obligation of generation to participate. How much ICAP do I have? How do I rate a generator? Does it count if I just pass a test or do I have to be there on peak or in times of shortage? And what do I agree to by being ICAP? Am I recallable, what are my obligations? Measure capacity provided; this goes to things like what do I actually do in performance. Match up supply and demand; do I have a clearing market, do I centrally procure it, do I have an auction, do I allow for bilaterals? And an enforcement mechanism, because voluntarily you would be a free rider.

Market designs are a mix of solutions. New York has the easiest performance standards. It has a short- term, monthly market. It was set up as a six-month market. It has an auction, but also bilaterals. It has no deliverability criteria. It has a locational requirement with deficiency provisions which are problematic. In PJM, the big item of interest is the movement from what was effectively a daily market to a seasonal market. The GridFlorida proposal is one of the first attempts to try to match up as closely as possible getting paid for capacity and meeting a true need, that is, being there on peak or at the time of system demand. Other alternative implementations are central procurement on a long-term basis, which is not implemented in the U.S., and a call option with a reserve level in the ground--that's pending.

I'd like to look at four important issues: The time step or obligation period of the market, generator performance and evaluation, deliverability and property rights, and the level of deficiency penalties.

Time step is the most important and least understood. It's a driver of measuring the reliability contribution of generators to the market and attracting new entrants. Super short-term markets tend not to offer the kind of investment security most people are looking for. To meet the basic objectives, the time step has to match the underlying reliability assumptions. This suggests that the right time step for most market reliability standards is annual. But because of demands of market participants for liquidity and ignorance of the underlying reliability analysis, everyone wants shorter periods. Reducing the time step can encourage migration of capacity out of the system.

Obligation period is the major driver for new entry. A shorter obligation period typically dilutes the deficiency penalty, which diminishes the incentive for long-term transactions and may discourage new entry. This also encourages migration of capacity out of the system when prices are higher elsewhere. It's another reason for annual markets or even longer.

On generator performance, we're looking for a way to measure a generator's relative contribution to meeting ICAP requirements. Ideally, there is a direct link between system demand and performance. The weakest solution is what New York had initially, which was you test once and you get paid whether you're there or not. Most generators, especially new entrants, like an emphasis on actual performance. It is fairest in terms of compensation, rewards good performers, and encourages new entry.

A key element to supporting new entry is clearly defined property rights. You have to measure them, figure out who pays for them, how long they keep them, and the market rules. For new entry, it's key that we resolve this. Everybody has to understand the rules of the game.

PJM has it right. There is a formal process, and once you've made that payment, you get explicit deliverability rights. It's in the tariff. In upgrading the system, you may create incremental transmission capability, so there will be more FTRs or TCCs, depending on which system made it available. A good system allows you to keep those.

New York has it wrong. There's no deliverability concept. There is a locational concept similar to deliverability, but it's assessed after the fact.

Deficiency payments are the enforcement mechanism. You need something with teeth to force a certain form of behavior. It is a tax. It's got to be a premium over the cost of new entry. It's also opportunity cost. And if you want to keep physical reliability and are concerned about people leaving the system, the deficiency charge has to reflect the spread to the other markets. The charges need to be applied to anyone, load or resource, that is short. Short must be defined as deficient at any time within the time step.

Discussion

Comment: A few points from a customer or retail supply perspective. One, people don't appreciate the relationship between reliability and what they're paying when it comes to installed capacity; they only see energy prices. Two, if you look at a time step process, that makes it difficult to add retail load. And how do you assess what that load is--if it's new load do you go under historicals, etc.? Three, if you're taxing everybody at the same level, that ignores effects you might have from demand side management or curtailment programs, which we're hopefully moving towards.

First Response: Retail access can be accommodated. What you want is a longer time step. Generators could come and go, but you have to meet the obligation for an extended period that could establish transfer prices monthly. I don't see long-term reliability as necessarily user friendly for retail. There is no problem between these markets and demand-side responsiveness if it's enforceable on a reliable basis. PJM has its ALM program. These are all proxies for getting what you want, and we have them because of other constraints.

Second Response: You can have a uniform tax, charge for the year, and allocate it to the hours where there is more probability of having difficulties. So you could send a signal through that price. I think we're talking about two different time frames--short-term demand response, and the long-term time range of ancillary services. Although in forecasting demand you have to take into account short-term responses, the demand forecast used to do a reanalysis to determine how much the queue is, the amount for the contracts for the capacity payments, is for a long-term market.

Comment: But we will not see significant demand response unless consumers see high prices. The point of ICAP is not to dampen price fluctuations and spikes. As far as the relationship between wholesale and retail prices, there are mathematical formulas by which wholesale prices of even ancillary services can be translated into efficient energy prices as seen by consumers. Hourly retail pricing would make that more rational.

Question: What is the relationship between the definition of emergency and prices rising in PJM?

Response: "Economic offers" are all offers of energy in real time in PJM. So an emergency effectively defines scarcity. The existence of the capacity market by itself doesn't get rid of volatility because capacity owners can do what they wish with their energy, sell it out or sell it in. It does change the shape of the volatility; you can have high prices, but they tend not to be as durable. What we saw during the peak times of 1999 was that prices went up, and if energy from the capacity resources was recalled, that had a short-term dampening effect on the price.

Comment: We have created a public good in reliability because we don't let the short-term markets clear. And the more we interfere with these short-term markets and put price caps on them, the bigger the public good we create. The question is how best to provide this public good of ICAP. How do we get it, how do we define it, how much do we need, where do we get it? The ISO or regulator has to decide. And who's going to pay for it is another set of questions. I think we'd make more progress if we get away from the notion that we have a competitive market in ICAP.

Comment: Why can't someone opt out of this market by submitting a demand schedule? You hear people talking about demand-side management rather than getting the demand side in the market in a normal way. It's great to have efficient refrigerators, etc., but what about getting the demand side in in a more formal way?

Comment: There is an argument that ICAP markets are so that regulators can avoid responsibility, and an argument that we need ICAP because the market is broken. I'm concerned that it's a slippery slope where we end up with the California problem of the market not working, so the system operator has to do it instead. So the system operator is making a decision about what the investment profile of the market has to be, and providing subsidies by way of ICAP payments to do this. It makes me inclined to say that we have to go back to this political process and get demand-side bidding in real time so they can absorb shocks over the business cycle. If we can't solve this, maybe we should quit kidding ourselves, and if we're going to end up regulating it one way we might as well regulate it another way.

First Response: I agree that it highlights the central role of demand-side sensitivity, and the priority should be to build that in real time. But given that we're not quite there yet, I think the ICAP market is the way to transition. But I would disagree that it's backdoor planning or IRP by another name.

Second Response: I'm skeptical that the ICAP market is part of a transition to better demand-side management. I think it makes demand-side management less attractive and makes it a longer transition. DSM is having trouble happening because we are not willing to allow market prices to get high.

Third Response: Part of the problem is that we always bring in the solution piecemeal. Once we start a certain way, we create a set of vested interests that want to keep the system in place. Then someone gets upset that you're destroying the property rights he's invested in for 20 years. Will those property rights get eroded for other reasons because we get demand management? Yes. That's a business risk, and somebody will take it. These have become almost political decisions about the willingness to transition, to absorb pain in doing it. You've asked the right question, and I don't think there's an obvious answer to it.

Comment: On the issue of insulating customers from the impact of high prices: A $1,000 price cap provides a lot of leeway, both for new generators to recover far in excess of their marginal costs and an incentive for customers to respond, if the market structures are in place to permit that response. We need to do a good job of developing market rules and structures that facilitate that response.

Comment: One of the interesting things is the importance of the inter-relationship of different products and the overall market design. I'm interested in the inter-relationship of the call option price, which is the energy, and the cap on ICAP. New England has filed proposals with a new capacity product which is the call option, but at a strike price of $1,000, and their future vision is that the strike price would become much lower.

Response: This works in PJM because of the $1,000 offer cap on the energy side without an explicit offer cap on the capacity side. It was a compromise, but it's adequate empirically; there's enough room to more than cover the spread.

Session Three: Power Plants and Information Disclosure

As it did in 1998, the Energy Information Administration (EIA) has proposed to limit public disclosure of certain electric power data elements. Its recently issued notices would reduce the number of power plants covered (only plants of 50MW or greater would be required to report certain data) and treat several central data elements (e.g., fuel type, quantity, quality, cost, and plant thermal output) as confidential. Some argue that current requirements are too burdensome, that most data collected should receive confidential treatment, and that public disclosure of individual plant data puts generation owners at a competitive disadvantage and impedes progress toward a competitive marketplace. Others contend that the electric power data collected and published by EIA is essential to the development of competitive markets, that the time lag in EIA's publication of the data minimizes commercial sensitivity, and that public regulation of the industry would be much more difficult if the data were not publicly available. Regulators have said that the EIA data is critical to discharge of their responsibilities. Environmental, consumer advocate and other public interest groups argue that regulators and the public would be the losers if such data were treated confidentially. Legal issues include EIA's information provision duties under federal law and Freedom of Information Act requirements. What has been the experience under the current requirements? What data do regulators and the public need to have? Will disclosure of such data help or hinder development of a competitive market? How can sensitive information be protected? How do we balance potential competitive harms to owners of generation and public policy favoring the public's right to information for making energy and environmental policy decisions and for regulating electricity providers?

Speaker One

What are the potential concerns with extensive information disclosure? One, in the Energy Information Administration (EIA) notices, they say firms will have a reduced incentive to invest in cost-saving technologies. If you are making an investment in a new technology that's going to reduce your costs, the benefit is the competitive advantage you receive from that lower cost technology. If your competitors immediately know about that, it reduces your competitive advantage.

Two, extensive information disclosure can aid in coordinated interaction between firms, i.e., agreement on output or prices. This can be a tacit agreement, where firms just act in a coordinated way, or it can be an explicit agreement. Such action is more likely when there are repeated, frequent interactions between firms. It's more likely if there are a limited number of competitors in the industry.

What are the problems with the proposed EIA reforms? They will make the FTC's work more difficult. The FTC relies on computer simulations which use comprehensive EIA data. Computer simulations are a very important part of anti-trust analysis. The computer simulations are used for regulatory reform planning and anti-trust analysis. There's much that goes into the analysis before it becomes a public complaint. We need to get the market power questions right during the restructuring process. The anti-trust authorities cannot come in afterward and address profit maximization; it's not what the anti-trust laws are designed to do.

In anti-trust, the FTC has historically looked at convergence mergers, about which there are three concerns: One, raising rivals' costs, e.g., where an electric company purchases an input for other generators and is then able to raise costs and benefit, usually in the wholesale electric market, by raising the cost of rival generators. Two, the elimination of direct competition between gas and electric, though it's questionable how much competition there is between them. Three, regulatory evasion, because the gas industry has been deregulated to the extent that a regulated utility can pass costs back to the deregulated affiliate.

If the EIA insists on maintaining the confidentiality of this information, what solution would at least allow selected access to the data? The FTC can independently subpoena the data from all the individual competitors, but that would be immensely costly. It's much easier to have the central data collected by the EIA.

But there are a couple of problems with selected access to the data as well. One, can the agencies actually maintain the confidentiality of the data once they've accessed it? The FTC and DOJ have strict confidentiality provisions; they have been tested in the courts, and are very solid. But the regulatory agencies often need to make the data available to the affected parties, and it's not as clear for them. Two, how are private simulation model vendors going to access this data if it is only available to agencies with legitimate purposes? If there aren't consulting firms and other private parties doing computer modeling, the FTC doesn't have the advances in the modeling that are required in order for it to do a good job. So it would force the regulatory agencies to bear all the cost burdens for the simulations. And with fewer people doing the modeling, it's not going to be as well done.

So the FTC's recommendation would be to allow at least selected access to the EIA data, even though it's not a wonderful solution. Selected access would allow the agencies to use even the most recent data for legitimate purposes. And, for the most part, confidentiality could be maintained.

Speaker Two

There are two very different kinds of competitive effects stories with information disclosure. The one that EIA clearly has in mind is the trade secret concept of information disclosure. Any information that is a source of competitive advantage is considered, in law, a trade secret. For example, the formula for Coke is a trade secret. It obviously has value. There are lots of sources of competitive advantage that rely on information. And it's important that we have legal regimes that protect this information from disclosure, because its confidentiality is what maintains incentives to invest in doing all the things that create this information and derive value from it.

Of course, we don't have a lot of these kind of trade secrets in the electric power industry. Another kind we might have is competitive strategies, but I can't come up with a scenario in which there is an important competitive strategy that people don't know in this industry and would learn from EIA. You have to wonder why the industry is clamoring for non-disclosure. Maybe disclosure of this information would be good for society because it would promote competition.

The usual anti-trust take on information disclosure is different from this trade secret concept of competitively sensitive information. There's a long history in anti-trust enforcement of concern about information sharing. I want to briefly talk about two recent cases. One case is the Airline Tariff Publishing Company case, ATP, brought in 1992 against ATP and eight major airlines. ATP is a big computer into which the airlines feed their fare information. So the airlines get each other's fare information, and so do others who can make use of it. In this case, there were several interesting types of conduct going on. One example is that the carriers were posting proposed future fares. They did this to tell their rivals what they were going to do, and see what their rivals would do in response. The airlines would often negotiate, as it were, through ATP and arrive at fares everybody could live with before the tickets started being sold. Some were complicated, like how one route was related to another. DOJ's complaint had two counts, information exchange and price fixing. The information exchange was obviously crucial to the price fixing.

A few years ago, DOJ filed another information-related case involving FDC spectrum options. The FDC concocted an incredibly complicated iterative procedure to auction a particular band of spectrum in 400 and some geographic areas around the country at the same time. The idea was that what people were willing to pay would depend on whether they were getting adjoining regions. The economists who devised this scheme said, we can fix this; we can allow them to iterate hundreds of times so they can make bids that are contingent on what other areas they are going to win these licenses in. The defendants, who devised the auction, figured these bids could be used to send messages. They used decimal places where cents would be to track numbers they wanted rivals to back off on. So they would throw in a bid on a particular region with these little numbers in a place that normally would be zeros, the region they were telling the guy they were bidding against to back off on, in exchange for which they would back off on the area they were submitting the bid in. These guys got the message, and backing off did occur.

Could the information EIA has be useful in reaching or enforcing a collusive agreement on electric power prices? It just doesn't seem very likely. It might be a little more likely that it could be useful in reaching a collusive agreement on capacity additions. But EIA doesn't have any confidential information on new capacity additions. And if people wanted to collude by disseminating this information, they would do it. They have the press. There is some evidence that it has happened in the paper industry. There is evidence that announcements of new paper capacity were used to coordinate capacity addition plans among competitors and restrict the increase of papermaking capacity in the U.S. So these things can happen, and information can serve important facilitating roles. But it's hard to see that the EIA information would play much of a role.

In terms of the history of anti-trust cases in this area, the most recent important court case that addresses these issues, from 1969, found that an information exchange in the corrugated cardboard industry did, in fact, have a significant effect on prices. As a result, that information exchange was held to violate the Sherman Act.

The greatest concern with the EIA information is that it would allow firms that might have market power to have a much better idea of how much market power they have and when it would make sense to try to exercise it. If you own substantial generating resources, you may be in a position to withhold some of that generation and make a lot of money. But you have to know that the demand is cutting the supply curve at a fairly steep point, and which point matters based on where your generation is.

Information of the kind EIA has could be useful in this regard, because it would help a generator construct the industry supply curve. That's how people use it in fact. But I doubt that this information disclosure can make much difference since most of this information can be gotten elsewhere, although perhaps less precisely. But that loss of precision probably isn't critical. In some circumstances, like California, you've got all of the information that you need that supply is extremely tight without any detailed information. And in other cases, I'm not sure that even a lot of information would be enough. You have to know things that are hard to know about demand conditions, for example, and outages. If you have that information, maybe you're in a good position to play these games. If you don't, then you're probably not.

Finally, like the FTC, DOJ's Anti-Trust Division has an interest in having this information out there for purposes of modeling competitive and other issues in the electric power industry. It hasn't done much of that, but encourages others to. And it has made use of work that others have done. This is very valuable. The states have relied on it extensively, and they don't have good sources for this information besides EIA. So DOJ does have concern that there will be harm to competition because the information needed to analyze competitive issues may not be available.

Speaker Three

I will focus particularly on uses of EIA data in environmental regulation and other environmental analysis.

Hearing about EIA's proposal to restrict the public availability of certain types of information is a bit like finding out you have a wheat allergy, because wheat is so pervasive in the food people eat. Suddenly you discover you can't have bread or pasta, but come to realize there are also a number of other foods that include gluten that you might not have realized.

That's what happens when you start thinking about some of the ways EIA data is used that might not be obvious. The power plant data that's available through EIA is a basic building block of policy development and policy analysis, both by regulatory agencies and non-regulatory entities, third parties as well as the private sector trying to participate in the electric industry. It's a central, national, consistent source of high-quality data that people can go to. When they say, "We're using EIA data," everybody knows what that means. They know the basis of the analysis and it gives a solid foundation for trying to come to some agreement on analysis.

It's very efficient for regulators to be able to rely on a central source of data. EIA data also supplements what some of the environmental regulatory agencies are able to obtain partly because of the minimum thresholds for information that they gather themselves, as well as issues of jurisdiction. A state regulator can't seek unit-specific data on generators not within their jurisdiction. And it's efficient for respondents to supply data in a consistent format to a central source rather than having to meet disparate requirements throughout the country.

Another of the basic building blocks that relies heavily on EIA data is the Environmental Protection Agency's EGRID, the Emissions and Generation Integrated Resource Information database. That's something that EPA has put together over the last several years, recognizing that there's a demand for consistent, high-quality data, particularly related to environmental characteristics of the electric power industry. EIA data contributes seven of the 18 data sources that EGRID relies on. It takes multiple years to go through the quality control processes at EIA and EPA in order to get in the public eye, and that time lag is significant when you're talking about confidentiality concerns. And there is the importance of power system models that incorporate data from the EIA database.

In terms of regulatory uses, EPA's acid rain program used EIA data throughout the process of developing the regulation and continues to use the data to keep the program up to date, to verify that the program's having the impacts they expect. States in the Northeast implementing the NOx program that came about from an MOU between the states also rely heavily on EIA data, particularly thermal output and fuel consumption data, because the environmental regulators in many instances are trying to move towards a system of environmental regulation that emphasizes efficiency rather than just looking at input to the generating process. Thermal output is one of the data components EIA is proposing to treat in a confidential fashion. Also, state regulators use the EIA data as a cross-check to make sure the data they're receiving from generators correlates with information submitted to EIA.

Other market-based programs are also in the works. There are ongoing discussions about SOx and mercury that would try to implement more market-based environmental regulatory programs. There, again, it's incredibly important to have the unit-specific data in developing the program. It adds to the credibility of the whole development process if people know what data is being used, how it's being used, if they can bring their own expertise to analyzing the data to make sure they're comfortable with how a program's being developed.

Some additional uses: Ongoing efforts to conduct air quality modeling, both at the federal and state levels; updating emissions inventories and emissions budgets for state regulators to make sure their states are complying with federal requirements; development of new regulations and updating existing regulations--public EPA databases are used both in the regulatory process and in public education processes. EIA data supplements that collected by the EPA. For example, units not covered under the acid rain program have to report to EIA, so increasing the threshold for submitting the data from ten to 50 MW would introduce significant gaps into the data available to states. That threshold issue is particularly of concern as there's greater emphasis on looking at distributed generation, smaller-scale generation.

And development of renewable portfolio standards. A number of states moving forward with retail competition have included renewable portfolio standard requirements. EIA unit-specific data is used in determining the baseline resource mix against which increases in the use of renewables is measured. Again, it's important because a lot of renewable portfolio standards take place in the context of a regional market, and it's useful for state regulators to be able to look on a broader basis.

One of the primary emphases in retail competition is the role of customer choice, and it's hoped that informed customer choice will replace some regulation. If customers are making informed choices about the types of resources to rely on for electricity, there's less of a need for a regulatory process to take into account issues such as fuel mix. Information disclosure would provide customers fuel and emissions data associated with their retail consumption. In Massachusetts, the big issue was, what information can you rely on? Suppliers were reluctant to give information. EGRID is now the primary source of information for emissions characteristics on Massachusetts labels.

Power Score Card is a private initiative undertaken by a number of public interest groups, including NRDC, UCS, and the Pace University Law Center, to provide customers information by measuring electric supplies according to eight environmental criteria including global warming, water impacts, land impacts, and toxics. It relies heavily on EIA and EGRID. If that information were not available, such a private initiative would not be possible.

Again, verification of marketing claims. Companies are selling products, and attorneys general need to be able to verify that their claims are accurate. This is third-party or non-regulatory analysis (there's also academic analysis, private sector analysis for new entrants to the market, and public interest analysis). There's all sorts of analysis ongoing that's not within the regulatory sphere that requires the availability of unit-specific data, state by state, region by region, nationally, in order to be effective.

Third-party, non-regulatory analysis is an important input to the regulatory process that would be missed if it were not available. A new entrant trying to get into a market needs to figure out whether they are making a good investment. There's a recent analysis on the performance of the pollutant allowance markets. There is a recent study of air emission reduction opportunities. Another example is evaluation of cost-effectiveness of DSM investment, looking at avoided electricity costs. All of these rely on detailed power system modeling that uses unit-specific data. And when you're dealing with companies that have half a foot in the wholesale markets and half in regulated retail markets, there are issues of cost allocation between regulated and non-regulated subsidiaries.

The availability of data is more critical now than ever. We're in a period of tremendous transition. It's very important to be able to apply as much analysis as possible to figure out what do we have right, what do we need to improve. The unit-specific data is critical for that. Competition means it's more important than ever to get information into the public eye. There's more and more evidence that there are market flaws and potential market power exercise. And there is an ongoing need to identify and measure successes and shortcomings.

Speaker Four

EIA exists for a reason. It is an information agency. When it gathers information that it does not disseminate, not only is it not doing what its statute says, it's not doing anything useful. I can't accept the premise that it should be gathered and given under a confidentiality agreement to the FTC for internal analysis with no public legitimation or to people in DOJ who decide whether to do anything with it.

I start with some basic assumptions. Sunshine is the best disinfectant; if you fear a problem, you deal better with it by letting everybody know more about it, not by impeding knowledge. The propagation of information tends to reduce insider power. That's the principle that our securities regulation is based on. The SEC's regulation, based upon the even-handed, open disclosure of information, is the most successful ever. And the concentration of generation in this market is already such that providers can get the relevant information for themselves without going to EIA. They can get detailed information about the plants by looking at the bid documents put out when these plants were put up for sale.

It's also vital to understand the timing question. We're not talking about posting the information that came out yesterday so that you can look at it today before you decide what the price of power is going to be tomorrow. We're talking about the plant-specific data that gets run through a mill and produces the data, 90 days at a minimum, usually 270 to 360 days later. We're not talking about information that is relevant to the prior control and prevention of market power, but to after-the-fact analysis of whether an abuse existed.

The EIA proposal would treat plant-specific fuel quality, consumption, financial data and thermal output as confidential. EIA has been gathering that information and releasing it for decades. It also proposes to exempt smaller units.

The proposal is based on the premise that the market is highly competitive; the notice said that "the proposed changes reflect the current highly competitive state of the electric power industry as a whole and the power generators in particular." But if you don't accept that premise, the foundation disappears. Given that we have markets with no meaningful price response curve, a high, almost prohibitive cost on storage, and high barriers to entry, particularly in terms of capital but also in terms of regulatory requirements, I don't accept this premise.

Are there examples of past problems with this data? I asked some folks in my office to put together a FOIA request asking whether there were any problems that had been cited in the past by this. We got a very straightforward response, a cardboard box of everything they had relating to comments on this, and there were zero citations of commercial injury caused by the public availability of that data. Every pool and ISO has asserted, and FERC has stated in every case, that market monitoring is key. Every one of them relies on plant-specific data, analyzed after the fact, months later, to find out whether their market monitoring has been successful, either on a day-to-day basis or structurally. In its absence, the assurance that these markets are healthy becomes nothing more than intuitive.

Don't forget, a lot of the country has no retail choice yet, they're still subject to the health of the wholesale market, and they have a right to know whether the wholesale market that's affecting their retail monopoly is healthy. And for those who have a standard offer, it is tested in many ways against whether the markets are healthy.

Some people have argued about whether the degree of market power should be measured by concentration. It should, and EIA's data understates the degree of concentration in two ways. I confess it overstates it because they tend to focus on investor-owned utility data and not on the non-utility data. But they understate concentration because they treat affiliates in who are separate companies belonging to the same board of directors as if they were different companies. And they understate it because they look at the national level, not at regions.

The most compelling thing I've seen recently, although it's not rare, is the NSTAR complaint. Demand is 5,200 MW. The available concentration that can come in by transmission is 3,200, so 2000 is needed locally. Of that amount, one company controls twothirds, another company controls 28%. Together, it's close to 93% for those two companies. FERC says ten companies provide power within this area, which is true. But eight of them collectively supply less than 10%. This is market power.

What do consumers want? Reliability; they care about price; they care about the environment. Whenever retail customers have made a choice, they have shown they care about the environment. If you trust markets, you ought to trust them in a utilitarian way. And it's vital to understand the environmental ramifications of the electricity you're buying. It is a significant portion of emissions on a worldwide scale. A third of U.S. emissions come from 3,000 power plants, and as we know from EGRID data, 90% of that comes from 300 power plants. That fact is an important part of what's going on in the world structurally and is important to many consumers. They want to know.

Discussion

Question: If EIA does decide that significant amounts of this information should remain confidential, would it be a Pyrrhic victory for those seeking confidentiality, since NGOs and environmental groups would then sue to get the information, and state regulators would step into the breach and require it?

First Response: Yes, if EIA were to decide to keep most of this proprietary, that would not end the question. I would then support litigation. But could other forms of information acquisition get the results society needs? I think ultimately no. States could pursue it on their own, but they have differing levels of authority, particularly in regard to environmental emissions. It's unlikely that they could come up with a common standard, and past efforts on customer disclosure have shown that it can take years to work on a common reporting form like EIA already has in place.

Second Response: Litigation is certainly a possibility, but a lot of cases never even get to discovery now. If you don't have a real cause of action or are just rummaging around in somebody's files, you're not only not likely to get into those files, you're likely to be sanctioned for trying. And if the information is turned over subject to protective order, it probably can't be used for purposes other than the ones the litigation seeks to vindicate. In fact, maybe only the plaintiffs' lawyers and consultants will have access to the data.

Question: Who really uses the EIA data for anything considered proprietary? When I look at EIA data, I end up finding another source because the EIA data is so out of date and not terribly useful since it's aggregated to a point where I can't do much with it.

Response: It's a good point, that there should be a high standard burden on entities arguing that it should be confidential to demonstrate what exactly is so commercially sensitive about it, that a blanket statement that we're concerned about competitiveness of the markets is not sufficient.

Question: The problem is the opposite; there's not enough data, and the information that's available raises more questions than it answers. For example, when I looked at a big study on withholding by Joskow and Kahn, it raised questions about how the California ISO exercised its responsibilities in dealing with outages and setting reserve requirements. You try to get that information, but you can't because it's confidential. If you look at the filings the CA ISO has made with FERC to support some of the market-based rates, there’s a long list of the data attachments, every one identified as confidential. What can we do?

First Response: Procedurally, it’s worth noting that EIA’s notice actually asks what enhancements can be made to the quality, utility and clarity of the information to be collected. So there is a door open for comment. This comment period is closed, though we're arguing for a second notice. Substantively, I agree that market monitoring is a vital function, and I hope that the people who do it in a nuts and bolts way can put together a serious, sophisticated set of statements about what information they need.

Second Response: I’m sympathetic to the notion that more information should be collected, but some of it probably should remain confidential. That doesn’t mean that qualified researchers shouldn’t be able to get hold of it. EIA or whomever should consider what procedures they can establish to allow qualified researchers to have access to the information on a confidential basis. There is precedent for this sort of thing.

Third Response: I’ve heard the term "qualified researchers" as well as "legitimate entities." How you define qualified and legitimate, and who gets to make those decisions, is critical. You might get tied up as much in that discussion as you do in whether the information should be public in the first place.

Comment: What do we do with the information once we get it? There's no consensus on how these markets ought to be organized, monitored, or evaluated. So we have to come to some agreement on benchmarks.

Question: I have been pushing for more definition, and I’ve seen three definitions of types of studies you could do. One is an HHI index or some variant on that, concentration data. One is a Lerner index or variant, and one is related to the Nash equilibrium analysis. As far as I understand, you might not need EIA data for the HHI. For the Lerner index and Nash equilibrium, you have to run at least a production cost model. Then you get into the question of how granular you have to get. Any other thoughts?

First Response: You need the data to even inform the discussion of what is market power. Given that the markets are relatively new, both wholesale and retail, I don’t think we have enough basis upon which to decide that one of those indices is appropriate, let alone all the issues introduced by transmission constraints and the actual operation of the system.

Second Response: The best data is data that was not collected for the specific reason you want to use it. Its legitimacy derives from the fact that it was collected, organized and presented in a way that was not result-oriented and that creates a norm against which you can test other things. So I don't accept the premise that you need to know how you're going to use it before you gather it. There is a question about whether the NEPOOL markets have been affected by changes in the startup times and minimum periods for power plants. Now the number of plants that say that they need at least four hours and probably six in order to get themselves started and take themselves off spin is much bigger. That may not be due to gaming, but almost all of these can be analyzed on the basis of the kind of plant-specific data the EIA has been gathering and propagating.

Third Response: While it is often the case that you don't need to know why you're collecting the data in order for it to be useful, there are lots of exceptions. There are different ways to measure something, and depending on what I think the economic effects might be and how I might use it in some sort of analysis, I would come to different views as to what the right measure of it is.

Comment: It seems like it becomes a slippery slope. Are we going to find that everybody has to defend themselves any time somebody believes they might have made a dollar more than they would have under regulation?

First Response: We can let electricity be competitive without letting it be competitive in secret. I don't think having the information out there is a drag on the industry. The industry is imbued with the public interest, and to vindicate that public interest, a great deal of information disclosure strikes me as a good thing.

Second Response: As far as the question, When is this going to be final and they're going to treat us like everybody else--not in our lifetime. We deregulated the airline industry in 1978. That remains a contingent decision subject to potential revisiting at any time. The data available on the airline industry is used on a regular basis as part of the basis for studies that attempt to show the continuing benefits of deregulation. If at some point they start showing the opposite, I suspect we'll go back to regulation. And that information is terribly important to the antitrust authorities, who have a very important role to play in this market, if the market does continue to be deregulated.