

Competition in Bilateral Wholesale Electric Markets: How Does it Work?

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Prepared for:



February 2016

Introduction

In one of the first laws establishing regulation of the electric utility industry, the Federal Power Act of 1920 (FPA) there was a recognition that there were two types of transactions commonly entered into in the industry that would be subject to regulation - with a different regulatory regime for each. Retail sales, or sales directly to customers who consumed the power themselves were deemed to be intra-state sales to be regulated by the states. But any sale for resale, i.e. a sale from any generating entity to a second entity that resold the power, was deemed to be an inter-state sale subject to regulation by the Federal Energy Regulatory Commission (FERC). This paper deals with the latter type of electric sale – wholesale sales regulated by the federal government. Up until the mid-1990’s, most wholesale sales were between vertically-integrated and state-franchised utilities, either short-term to take advantage of one utility having cheaper power at a moment in time than another utility, or longer term to provide needed capacity to the purchasing utility. Both of these types of transactions were mostly conducted under bilateral contracts between the buyer and the seller – the contracts being submitted to FERC for approval according to the statutory framework of the FPA.¹ Until the mid-1990’s, short-term transactions were typically conducted on a split-savings basis, meaning the savings resulting from the transaction were evenly split between the buyer and seller. Longer-term transactions were typically cost-based, with the seller allowed to earn a regulated return on the sale.

For a variety of reasons beginning in the mid-1990’s there was a development of a new type of market, made possible by the deregulation or restructuring process which for the first time allowed retail customers in some states to choose their electric supplier. It was thought at the time that effective retail competition required utilities to divest all or some of their power plants to third parties. At the same time, changes in Federal law and regulation were making it considerably easier for third parties to enter generation markets and have guaranteed access to utility transmission systems.² Thus new wholesale markets began to be developed in many regions of the country

Because of concerns about fairness, these new markets formed around independent system operators or regional transmission organizations independent of the transmission and generation owners in their regions. These regional operators also adopted a new form of wholesale market for their regions, a centralized market based on bids submitted to the market operator from individual generators. These bid-based centralized markets utilized locational marginal pricing (“LMP”), whereby generators bid at their location into a centralized market and bids are accepted or rejected based on projected electricity needs for the relevant period. While

¹ There were certainly exceptions – many utilities operated under pooling arrangements based on multi-lateral contracts among several utilities – but they were still based on “umbrella” contracts among the parties and approved by FERC.

² For a fuller description of the history and development of wholesale markets in the U.S., see “Evolution of the Electric Industry Structure in the U.S. and Resulting Issues,” Prepared for Electric Markets Research Foundation, Navigant Consulting, Inc., October 2013.

generators are dispatched from lowest-cost bid to highest-cost bid up until the point that expected demand plus a reasonable margin is satisfied (and reliability constraints are recognized,) all successful bidders receive the highest priced successful bid at their location.

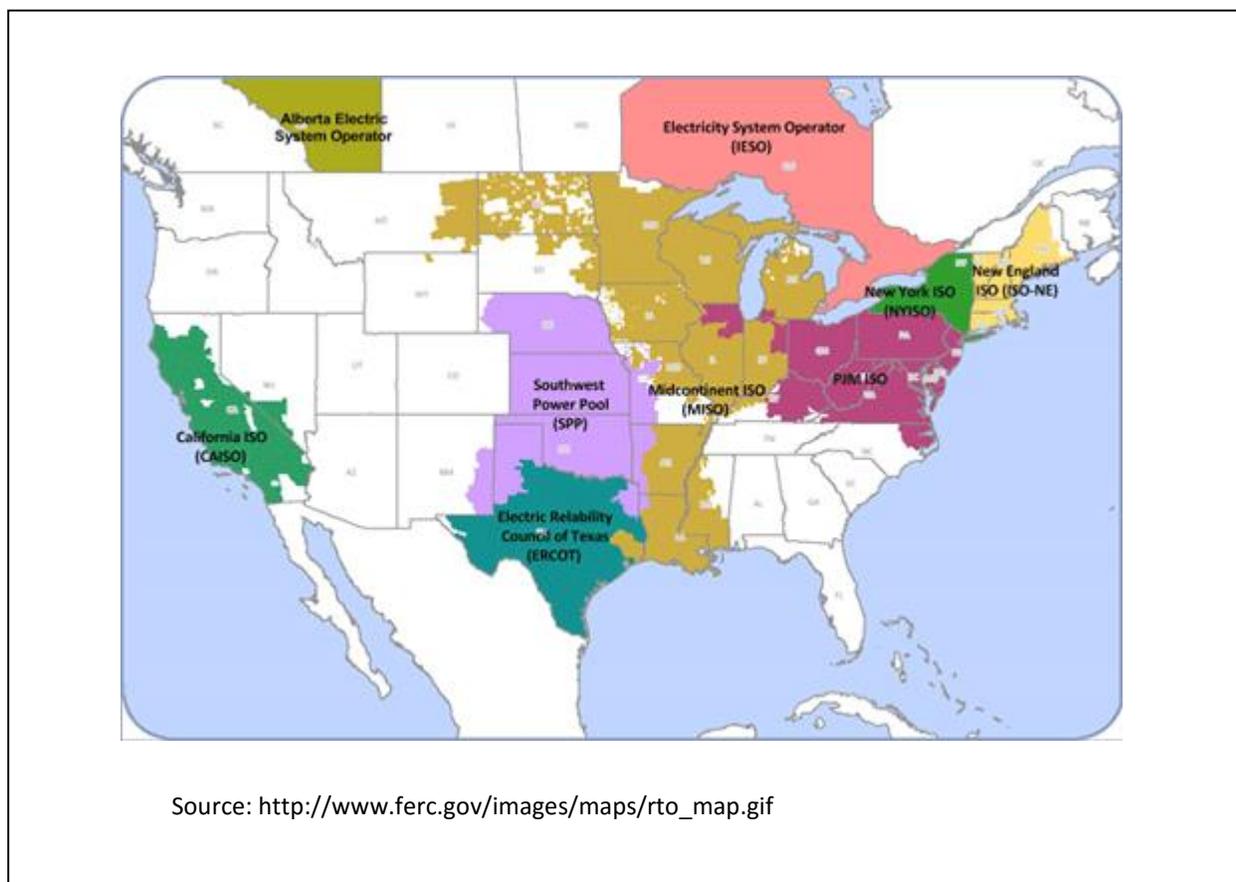
Another feature of these new LMP markets is that rather than charging for transmission service based on a contract path, users of the transmission system were to pay congestion charges based on the difference in locational prices between the point of injection and the point of receipt (i.e., the location of the seller and the location of the buyer). Market participants were either allocated, or had to buy through auctions, so called financial transmission rights (“FTRs”) which give them rights to use the transmission system without paying congestion charges. In this way, market participants could hedge their transactions by owning FTRs.

The theoretical basis of LMP markets is that individual generators bid into the market at their marginal cost (the cost of producing their next kilowatt-hour) because to bid less would result in their losing money if they were to win the bid and have to generate and to bid more might mean that they don’t get dispatched even though the transaction would be profitable to them. The market operator (RTO or ISO) chooses winning bidders based on the lowest cost combination of bids that can be dispatched in real time within reliability constraints. Thus, in theory, generators presumably will have incentives to operate as efficiently as possible, because only the lowest cost generators get paid, and their profitability depends on getting dispatched and having costs below the LMP. Profits are simply the difference between the LMP paid to all generators at a given location and the generators actual cost for the period for which its bid was submitted. These bid-based LMP markets are most often referred to as “organized” wholesale markets or “centralized” wholesale markets. This paper refers to centralized markets, as the term “organized” gives a false impression that other markets types are not organized.

Figure 1 shows the seven U.S. ISOs and RTOs which have formed since the mid-1990’s and that are using bid-based LMP markets.

Figure 1.

North American RTOs and ISOs



The geographic areas in Figure 1 not covered by RTOs (or ISOs) are operated by vertically-integrated utilities that are still regulated by states (or by cities and towns in the case of municipal utilities or Boards in the case of cooperative utilities). In all of these cases, the utilities operate in wholesale markets governed by contracts between and among the participants in those markets – contracts that are regulated by FERC. Because of this characteristic, these wholesale markets have become known as “bilateral markets” even though it is a bit of a misnomer, as bilateral contracts also are a significant part of centralized markets.

This second market structure for wholesale competition – bilateral markets – relies on negotiated wholesale contracts or agreements between willing buyers and sellers. Once an agreement is reached, either the buyer or seller arranges transmission service to complete the transaction. While centralized markets are based on hour-ahead or day-ahead spot markets, bilateral markets can be hourly, daily, weekly, monthly or multi-year – and are often comprised of all these types. And while bilateral contracts are also negotiated in centralized markets, at least currently, such contracts are usually just financial and short-term in nature. Bilateral agreements can be the result of arms-length market negotiations, formal requests for proposals, informal or unsolicited

bids for sale or purchase, or can simply result from a phone call between two parties for a short-term purchase or sale. The price charged for power in bilateral markets depends on whether or not the seller has market-based rate authority under the Federal Energy Regulatory Commission's (FERC's) rules. Wholesale sales into areas where the seller does not have such authority would be made at FERC-approved cost-based rates.

Bilateral markets almost always involve utilities that still have a legal or regulatory obligation to meet the current and future needs of their retail and wholesale requirements customers. Utilities within bilateral markets dispatch their generating plants in merit order (that is lowest to highest cost) taking into account transmission or reliability constraints. In this way, they operate in the same way as the centralized markets – except that their dispatch is based on actual costs rather than bid prices. And utilities in bilateral markets will buy from third party generators when it is cheaper than running their own generation, or will sell to third party purchasers when they have excess power available which is at or below the cost of the purchaser's alternatives. Savings from such purchases or revenues in excess of costs for such sales are used to lower costs to the utilities franchise retail customers.³ The fact that there is substantial competition in bilateral markets for sales and purchases among utilities and independent generators and marketers is a point that is often missed or ignored by the proponents of centralized markets. The absence of a centralized market for such transactions does not by itself mean that the bilateral markets do not provide the same kind of competitive efficiencies to their participants as centralized market participants.

Bilateral markets differ from centralized markets in many other ways. For example, in bilateral markets, utilities recover their fixed costs through the regulatory process – agreeing to meet the existing and future needs of their customers – plus an adequate reserve margin, in exchange for receiving a reasonable return to investors on prudently incurred costs. In centralized markets, generators get paid the market clearing price for successful bids into the centralized dispatch. Generators recover some or all of their fixed costs (or perhaps even more than their fixed costs) from the difference between the market price for power and their actual operating costs.⁴ For fully depreciated plants or for nuclear plants for which stranded investment costs have been fully recovered, revenues from market-based sales in excess of actual variable costs amount to pure profits for the seller.

Over the past two decades, there has been a continuing debate on the merits of these two different types of market structures for the electric utility industry. Bilateral markets have been criticized by proponents of centralized markets, particularly in the early years of electric restructuring. The most vocal of these opponents of bilateral markets at the time were owners of independent generating plants who gambled on their view that market prices of electric power generated from new gas plants would be lower than the embedded (historical) costs - which

³ In some states, a utility is allowed to retain a portion of these savings for its shareholders, as an incentive to the utility to seek out as many cost-saving opportunities as possible.

⁴ While the difference between market clearing prices and the utility's actual costs was originally intended as the only means to recover fixed costs in centralized markets, the lack of new generation construction, possibly because of price caps, has led at least the New England ISO, the New York ISO, and PJM to also offer locational capacity payments to generators available during peak periods. Their hope is that the availability of capacity payments will lead to new generation construction when reserves tighten.

formed the basis of prices of vertically-integrated utilities - and lost their bets when the price of gas skyrocketed in the early part of the 1990's.

Since gas prices have declined significantly since then, the calls for restructuring of bilateral, traditionally regulated markets has subsided considerably, but are still being heard in some quarters. Opponents of bilateral markets today continue to argue that vertically-integrated utilities either explicitly deny access to their transmission facilities even when capacity is available, or use delay tactics to stall having to provide access, thus avoiding competition. They also argue that regulated utilities have an incentive to run their own generation even when cheaper power is available in the competitive wholesale market. Until FERC Order 1000 was recently issued, they argued that they were excluded from utility transmission planning processes so that their needs wouldn't be met. Some still believe that Order 1000 wasn't sufficient to meet their needs. But perhaps the main argument used by the proponents of centralized markets (and opponents of bilateral markets) is that utility customers in bilateral markets assume all of the risks of market mistakes by the regulated utility, as opposed to centralized markets which they argue places all of the risks of mistakes on the unregulated generators who only get dispatched if they can beat the locational marginal price. This argument is addressed later in this paper.

On the other hand, those participating in bilateral markets believe that they have the better industry market structure. They argue that the benefits of vertically integrated utilities operating in bilateral markets are optimized by, among other things: (1) being accountable for reliability and meeting service obligations; (2) including fuel choices and externalities in integrated system and resource planning to ensure low costs, fuel security and diversity, and long-term reliability; (3) lowering costs through joint planning; (4) passing benefits of wholesale competition through to customers without requiring those customers to pay the transaction costs of choosing their supplier and operating a centralized market; (5) avoiding stranded cost recovery problems that limit many benefits of competition; (6) managing a bulk power system on an efficient scale without the cost overlay of separate regional transmission operation; and (7) integrating risk management on behalf of customers.

Bilateral market participants and their regulators, as well as some observers of restructured markets, have also expressed continuing concerns about centralized markets. These concerns primarily revolve around the lack of new capacity construction in centralized markets, even with new capacity payment programs and capacity markets that have developed to encourage the construction of new capacity. These concerns in turn lead to further concerns about the future reliability of power supplies in the centralized markets. A recent report by the Electric Markets Research Foundation suggests that these concerns are real, and that bilateral markets have done a better job to date in ensuring that new generating plants are added to ensure long-term reliability of the electric system.⁵

Today, about 40% of electric consumers in the United States are served by vertically-integrated utilities operating in bilateral markets. Over the past several decades, some states and utilities have retreated from electric restructuring or from retail competition or customer choice. Virginia is one state that passed legislation reversing its earlier decision to allow choice for all customers.

⁵ Christensen Associates Energy Consulting. "Ensuring Adequate Power Supplies for Tomorrow's Electricity Needs," Prepared for the Electric Markets Research Foundation, June 2014.

Legislation was also introduced in Michigan and Ohio, and other states are reviewing the situation. There is not a firm answer to the question as to whether restructuring, retail choice, and RTOs and ISOs have brought any real benefits to electric consumers. Quite a few studies have been done looking at consumer prices in both centralized and bilateral markets, but results have largely depended on who does the study. Most of the academic studies (as opposed to studies performed by consultants under contract to a market participant) to date have found either little or negative benefits attributed to centralized markets.⁶ The debate continues, although there does not seem to be much movement at the present time in either direction.

The purpose of this White Paper is to explain how bilateral markets operate. The author believes that bilateral markets provide for fair and efficient competition in wholesale markets and that such markets are a better way to make wholesale competition work for the electric consumer. But more importantly, it is our goal that a better understanding of how bilateral wholesale markets work will lessen any remaining legitimate concerns about the working of these markets. This paper is not a treatise opposing increased wholesale competition. All should embrace and support wholesale competition and we believe that Congress settled the issue with the Energy Policy Acts of 1992 and 2005 that established wholesale competition as a national policy. We also believe, however, that centralized markets are not needed to make wholesale competition work, and in fact bilateral markets can better provide the benefits of increased wholesale competition without many of the risks and problems being encountered by centralized markets.

Long-Term Planning for Adequacy and Reliability in Bilateral Markets

The most important task for a traditionally, vertically-integrated utility operating with an obligation to serve franchise utility customers is planning generation, transmission and distribution in concert to ensure that power will be delivered to customers reliably when and where they need it, and at the lowest reasonable cost. This is one of the main attributes that sets vertically-integrated utilities operating in bilateral markets apart from disaggregated companies with retail competition operating in centralized markets. In the case of vertically-integrated utilities, there is centralized planning to build generation, transmission and distribution in a coordinated fashion, accounting for reliability assurance, costs, environmental impacts, technical needs (e.g., voltage support) fuel diversity concerns, plant and transmission line siting issues, and other factors. In the centralized markets, market participants decide where and when to build new generation, and transmission planning usually follows those decisions, although there is some attempt now being made to try and coordinate generation and transmission planning a little better. But clearly, greater coordination is possible within vertically-integrated utilities.

Generation Adequacy

The first step in the long-term planning process of vertically-integrated utilities operating in bilateral markets is to determine how much generation will be needed for the planning horizon,

⁶Blumsack, Seth, "Measuring the Costs and Benefits of Regional Electric Grid Integration," *Energy Law Journal* 28:1, 2007.

including generation capacity to be held in reserve to ensure supply adequacy under most conditions. Prior to the 1970's, electric demand could pretty much be projected just by extending a straight line from historical trends. But with the advent of higher prices beginning in the 1970's and more complexity in consumer demand patterns, demand forecasting has become more complex and involves the use of sophisticated econometric models. And whereas the planning horizon, prior to the 1970's may have been as long as plant lifetimes (i.e., 20-30 years,) no utility today is comfortable with planning generation more than 5-10 years into the future because of greatly increased uncertainties further out. Thus, utility planners today (within vertically-integrated utilities) are typically forecasting demand for electricity over a planning horizon of at least five years, but probably no more than 7 – 10 years.

Most vertically-integrated utilities today utilize integrated resource planning (“IRP”) to establish resource plans to meet forecasted demand. In some cases IRP is undertaken under a state legislative or regulatory mandate with specified rules and procedures and in other cases the process is more informal. In every case, the IRP processes are overseen by the respective state Public Utility Commissions (PUCs). IRP processes consider both demand-side/efficiency options and supply-side generation options to meet forecasted demand and a reasonable reserve requirement. And in considering supply-side generation options, the IRP process looks at both the opportunity to make long-term purchases from third-party or affiliated merchant generators and the opportunity to self-build generation and put it in the utility's rate base. Some states require a formal bid process to choose between self-build and third party options before an IRP receives final approval.

In conducting the IRP process, utilities typically look at economic options to reduce demand or increase efficiency in the use of electricity first. When these options are less costly than alternative means of meeting demand, they are incorporated into the resource plan. Another important piece to the IRP process is plant retirements. Utilities have to look at whether any existing plants must be retired, either for technical or economic reasons. The remaining need is then assessed, and in states where required, an RFP (request for proposal) is developed to seek bids on satisfying the incremental need. As forecasts change each year and a new year is added to the planning horizon, utilities conducting IRP typically develop and issue RFPs as often as every year or when an incremental need is determined. Other utilities, third party generators, and affiliated generation companies (i.e., power generation affiliates to the utility conducting the bidding process) can all compete to meet the identified need. In some states utilities are also asked to develop a self-build proposal to serve as a baseline to compare against competitive bids.

Utilities evaluate the competing bids on several different dimensions. The first, of course, is overall cost – taking into account not only the bid price, but the cost of any transmission upgrades that will be needed to complete the proposed transaction.⁷ Reliability is of course also a critical factor. Generators may propose locations for their plants that might either reduce or increase the overall reliability of the electric system. The proposed terms and conditions are also critical – some sellers may have limitations in their bids which increase the risks or costs to the purchasing utility. And of course sellers will try to transfer as much risk to the buyer as possible. In some cases, the proposed fuel source for the generation is important. There may be fuel

⁷ In some cases, RFP participants may be asked to incorporate transmission costs in their bids, i.e., provide a delivered price.

delivery concerns, or there may be concerns about potential shortages or price uncertainty. Vertically-integrated utilities with service obligations are rightly concerned about becoming over-dependent on any particular fuel source. Environmental rules – both current and potential – will also enter into the decision. Utilities will look, for example, at how the cost of carbon emissions that might be imposed in the future affects the potential resource choice. Or the utility may decide to self-build nuclear plants after considering both fuel diversity and environmental concerns.

Upon completion of this analysis, the utility will select its preferred supply-side options and present their proposed choices, formally or informally, to state PUCs. In the case of some states there is also an independent evaluator that reviews the utility's decision-making process and renders its own recommendation. State PUCs may accept the utility's choice, or send them back to the drawing board. In IRP proceedings, losing bidders or any other member of the public may make their case as to why the utility made a wrong choice. But once the IRP is approved by the PUC, it becomes the utility's plan for meeting future demand – at least until the next IRP is developed. And with respect to particular contracts that the utility enters into for a wholesale purchase, the seller must get FERC approval for the transaction. FERC will look especially at whether the IRP process was conducted fairly, whether there was open transmission access available to competitors, and whether the seller possessed market power that resulted in an unfair price.⁸

The oversight of this process by state commissions and ultimately by FERC is important, as there may be complaints from third-party generators that utilities are unfair and discriminatory in the selection process – either because they favor their own or affiliated alternatives, or that because they own both transmission and generation, they will deny or delay transmission access for third parties to ensure that their own generation is selected. Both state and federal review processes have been established to deal with this concern and ensure that resource procurement is conducted without undue preference or discrimination. As will be noted later, the tremendous amount of non-affiliated bids and contract awards by vertically-integrated utilities in bilateral markets suggest that the process is working. This evidence also demonstrates the tremendous amount of competition for incremental generating needs that exists within bilateral wholesale markets. But most importantly, it demonstrates that the integrated resource planning process within vertically-integrated utilities, operating in bilateral markets, ensures that in the long-term, customers are getting the best possible deal on generating capacity required to meet their needs. Later, this paper discusses how bilateral wholesale competition works to ensure short-term efficiency as well.

In centralized markets, integrated resource planning does not exist. Generators typically do not have an obligation to serve. This obligation, if there is one at all, rests solely on the distribution utility which has to rely on wholesale purchases to meet the needs of default customers that do not choose an alternative supplier. When power supplies are tight – for example in the hot summer months or during a polar vortex – prices in the wholesale market surge and customers will face much higher and volatile costs. And while distribution utilities can hedge this volatility in centralized markets by entering into long-term bilateral contracts with generators, the evidence

⁸ Allegheny Energy Supply Company, LLC, 108 FERC ¶61,082 (2004).

thus far suggests that such contracts are not readily available.⁹ To ensure that there will be power available when needed, RTOs and ISOs in some cases have implemented capacity markets or in the case of PJM, have offered incentives for availability during peak situations. But because utilities in those markets in most cases don't have the obligation to maintain adequate reserves, many will be left to make capacity payments and pay the market clearing price of the ISOs' energy auctions, which again could be extremely high in times of shortages. And it is not clear how shortages would be allocated if there simply is not enough generation to meet demand. All of these uncertainties in centralized markets are handled through the IRP process in the vertically-integrated, bilateral wholesale markets.

Another key concern is the fact that in centralized markets, there is no means by which to ensure that generation decisions will be made based on lowest overall costs. In fact, the opposite may be true, especially where merchant generators do not face the full costs of transmission improvements that are needed at the location chosen by the generator. If these costs are socialized, as is currently the case in several of the centralized markets, then retail customers are ultimately paying the costs of poor location decisions. In fact, generators may be incited to locate where land, water, and fuel is the cheapest, without regard to incremental transmission costs or the overall impact to customers. Again, IRP in vertically-integrated, bilateral markets addresses this problem by ensuring that transmission (and all other) costs are included when making resource decisions.

Finally, in centralized markets, there is a loss of economies of scope that come from joint planning and operation of generation and transmission. A Cato Institute report found that the loss of such efficiencies, which result from the ability to coordinate planning and operations, were never considered in the original rush to centralized markets.¹⁰ As stated by Dr. Robert Michaels, the author of the study:

A review of the debate surrounding electric utility restructuring in California – the first state to embrace restructuring – reveals that legislators and regulators regarded vertical integration primarily as a tool that incumbent utilities could use to perpetuate their market power. They thus disregarded the benefits that might accrue from vertical integration and used the force of regulation to encourage the sale of generating plants to independent power producers. The idea was to create a competitive market structure in the electricity generation sector. Unfortunately, the costs associated with this experiment in California and elsewhere have yet to be compared with benefits in any economically meaningful way.

A proper comparison of the two suggests that restructuring is presently off course.
(Michaels, page 1.)

The fact that the loss of efficiencies from vertical integration was never considered in the rush to centralized markets is quite baffling, and as Dr. Michaels points out, quite telling as well.

⁹ American Public Power Association, "Power Plants Are Not Built on Spec 2014 Update," 2014.

¹⁰ Michaels, Robert J. "Vertical Integration and the Restructuring of the U.S. Electricity Industry," by the Cato Institute, July 13, 2006.

Transmission Planning

Once the resource plan has been developed, it must be incorporated into a transmission plan. As noted above, the cost of transmission has already been considered when resource decisions were made. But once the resource plan is adopted, transmission must be planned and built to integrate any new generation into the grid. At the same time, other utilities, either within the utility's control area or neighboring utilities, or merchant generators may have requested long-term transmission service. The transmission planners must also consider such requests in developing overall transmission plans.

Transmission planning processes at the local, state and regional levels provide a forum for customers, regulators and other stakeholders to receive information concerning the anticipated transmission expansion plans of the entities in the region, including assumptions and methodologies used to develop these plans. However, transmission providers generally have the right to accept or reject any proposed modifications to their transmission expansion plans (except as provided by contract). Transmission providers (and their state commissions) maintain the ultimate authority over transmission expansion plans.

Thus, bilateral market regions are conducting inclusive transmission planning processes that ensure that actual needs of the region are satisfied. A caveat is, however, in order. Utilities operating in bilateral markets cannot be expected to plan for or construct speculative transmission facilities or transmission facilities for which cost recovery is not assured. Because the primary venue for cost recovery in bilateral markets of new transmission facilities is the state PUCs, utilities need to be able to ensure those state commissions that what is proposed is either needed for serving customers, or that there will be sufficient revenues from the provision of wholesale transmission services that the costs of the new facilities will be recovered. Utilities can generally not expect that states would allow recovery on assets that are built on the premise that they will provide some nebulous regional benefit – unless those who will benefit from such facilities are willing to pay the cost. This construct differs from centralized markets, where the RTOs/ISOs recover transmission costs based on FERC-approved tariffs. Once those tariffs are approved, transmission owners in centralized markets are assured of cost recovery and do not need state approvals.

Cost Recovery

An important component of ensuring resource adequacy and reliability within bilateral markets comprised of vertically-integrated utilities is assured cost recovery. Because vertically-integrated utilities build facilities which may take 30 years for full cost recovery, or enter into bilateral contracts to buy power over long periods, they need assurance of recovery of prudently incurred costs, including a fair return on investment. In some states, once a resource decision has been certified by the state PUC, the utility is automatically eligible for recovery of prudently incurred costs. In other states, the utility must request cost recovery in a rate case at (or after) the time the plant begins service.

The issue of cost recovery has been a major part of the debate between centralized markets and bilateral markets. Merchant generators argue that the rate-basing of power plants has placed all

of the risk of generation development on ratepayers, has resulted in utilities favoring self-build options over purchased power in competitive wholesale markets, and has resulted in utilities' either over-building or "gold-plating" facilities. They argue that in disaggregated, centralized markets, all of the risk of generation development is placed on the developer and customers do not have to pay if merchant generators make poor economic decisions. They claim that because they are only able to recover the market price for power, they may or may not be able to recover their fixed costs – or, if they are out of market, will not recover any costs at all.

There are many reasons why these arguments about all risk being placed on utility customers in traditionally regulated markets, and there being no commensurate risks on customers in centralized markets are overblown. First, utilities in traditionally regulated areas are by no means assured full recovery of prudently incurred costs. Rate decisions are made in a political environment and cost disallowances are frequent. It is also unlikely that a utility, over time, will recover its full cost of capital given its risk profile. In fact, methodologies to determine appropriate returns on equity are often biased against cost recovery that accounts for all risks.

As to incentives to build generation when there are cheaper long-term purchase options – the IRP process already described ensures that this scenario is highly unlikely. A state commission is not going to approve a purchase by a utility on behalf of its native load if there are cheaper (and better) options available. And FERC has made it clear that it will not allow sales between affiliated companies unless a fair and non-discriminatory procurement process has been completed.¹¹ Finally, the record of vertically-integrated utilities making substantial purchases from unaffiliated third parties as a result of long-term procurement processes belies the arguments of the merchant generators.

The IRP process also ensures that utilities will not overbuild or "gold-plate" facilities. Since utilities will not likely be able to recover any more than the costs of facilities that were certified or informally approved by the state commissions before construction, and since those approvals examined the costs of the facilities relative to alternatives, there is no incentive to spend any more than is absolutely necessary. Again, there is no guarantee of cost recovery. And the IRP process itself will ensure that utilities do not build more than is absolutely necessary.

Utility proponents of centralized markets conveniently and consistently fail to remind the public that they recovered their "stranded" costs through the regulatory process, effectively paying off the fixed costs of their generation. Thus, they really had little risk when they entered the centralized markets – such risk had already been assumed by customers. For many of these utilities, they have thus been able to recover their fixed costs more than once – and with the advent of capacity payments in centralized markets, will become even more profitable – and it is utility customers who will be paying again for generation capacity.

Finally, the increased risk presumed to be assumed by generators in centralized markets is not cost free to customers. Generators in centralized markets will not be satisfied with cost recovery over a 20 -30 year life of the project, but rather will insist on cost recovery in a much shorter time period (probably 10 years or less). Thus, in considering whether to build a plant, the merchant will look at its ability to recover costs in this shorter period, and will only invest when

¹¹ *Allegheny*, op. cit.

prices go high enough (and are projected to remain high enough) to provide such assurance. In contrast, vertically-integrated utilities with a service obligation must build when reserves are insufficient, without regard to the market price. Thus, customers will pay more for capacity in centralized markets – they are in effect ensuring a shorter recovery time period for the merchant generator, reducing their risk.

In addition, merchant generators in centralized markets will have a much higher hurdle rate for investment. They will not be willing to accept the same returns earned by utilities in traditionally regulated markets, which are risk adjusted. Thus again, they will only invest when it appears that prices will support a higher return, which may mean that reserve margins will be greatly reduced before new generation is built. As market prices rise due to shortages, developers will only step in when they believe the potential return from the project reflects the greater risk. It is the customers within centralized markets who bear the costs of those increased returns needed to reflect greater risk, just as customers in bilateral markets may face greater costs by assuming part of the risks of new construction.

The central question, of course, is whether or not the increased risk and attendant costs in centralized markets for new generation capacity and the ISO/RTO costs of establishing and operating these markets are more than offset by any efficiency gains from this particular form of wholesale competition. If there are any efficiency gains, one would expect them to appear in the form of lower prices to customers in centralized versus bilateral markets. But as mentioned earlier, there is no evidence (or at best mixed evidence) to date of any significant cost savings. And early in the restructuring process, many states undertook state or regional reviews of the costs and benefits of restructuring. Those states that did not restructure found that costs would exceed benefits.

Generation adequacy in the long term is only one piece of the puzzle in examining the differences between bilateral and centralized markets. One could even hypothesize that short-term efficiency gains in centralized markets make up for any losses in the efficiencies that would otherwise be available from integrated resource planning and economies of scope. In the next section, short-term efficiency in vertically-integrated, bilateral markets is discussed, and compared and contrasted with short-term efficiency in centralized markets.

Short-Term Efficiency in Bilateral Markets

The Process for Optimizing Assets in the Short-Term

In the short-term, all of the assets available to the vertically-integrated utility (including available purchases from third parties) are optimized using economic or “merit order” dispatch based on reliability constraints, also referred to as “security-constrained economic dispatch.” Security constrained economic dispatch is designed to weigh all factors that affect the incremental costs of reliably operating each available generation source in order to determine which units will be committed for use and how those units should be dispatched in real time. The FERC has

properly described economic dispatch to include both a forecasted unit commitment process (to determine which combination of units will be most cost-effective for dispatch, based on the expected load) and to ensure those plants are ready to operate when called upon **and** a real-time economic dispatch process (to determine how and to what extent the committed units should be operated to meet current system load).¹² Thus, economic dispatch actually includes two processes – unit commitment and real-time dispatch.

While economic dispatch can occur within a single utility operating company, in many cases even in traditionally regulated, vertically-integrated utility markets, economic dispatch occurs for multiple utilities within a region. There are two cases where dispatch involves multiple utilities in these markets – within public utility holding companies that own multiple operating companies (known as holding company pools),¹³ or within a power pool where multiple utilities have voluntarily agreed to pool their resources. The Florida Municipal Power Pool, which began operation on July 1, 1988 and includes the power-generating resources of Florida Municipal Power Agency (FMPA), Lakeland Electric and Orlando Utilities Commission (OUC) is an example of such a voluntary pooling arrangement among unaffiliated companies. The Florida Municipal Power Pool serves the combined electric needs of 20 communities in Florida.¹⁴

Under either a holding company pool or power pooling agreement, each participating operating company makes its generating resources exclusively available for economic dispatch by the pool. The pool operator considers all available generating resources controlled by the participating operating companies¹⁵ (as well as purchased power opportunities) and uses unit commitment computer modeling to select the combination of resources that will most economically serve the next day's forecasted load. This unit commitment projection is then provided to the transmission owners, which determines whether any transmission limitation prevents its execution. If any such limitation is present, then the unit commitment is adjusted to take the limitation into account. During the next day, the pool operator utilizes real-time economic dispatch in order to optimally select the committed resources to meet their load at the lowest possible cost, while accommodating variances between projected system conditions and actual conditions and adjusting generation as directed by the transmission business unit to remedy any transmission constraints.

Unit commitment and real-time economic dispatch are separate, but highly integrated processes and are guided by three fundamental objectives within vertically-integrated utilities: (1) maintaining system reliability; (2) minimizing costs; (3) operating generating units within their design limits, and (4) meeting environmental or other public policy requirements. There are of course many influencing factors, both internal and external, that affect the unit commitment and real-time economic dispatch processes. The overall economic dispatch process in bilateral

¹² FERC Staff, "Economic Dispatch: Concepts, Practices and Issues," Presentation to the Joint Board for the Study of Economic Dispatch, Palm Springs, California, November 13, 2005.

¹³ American Electric Power, Entergy, and Southern Company are examples. Up until its repeal in 2006, the Public Utilities Holding Company Act of 1935 required "Registered Holding Companies" to act as a single integrated system. And while the Act has been repealed, all the original Registered Holding Companies have retained this feature.

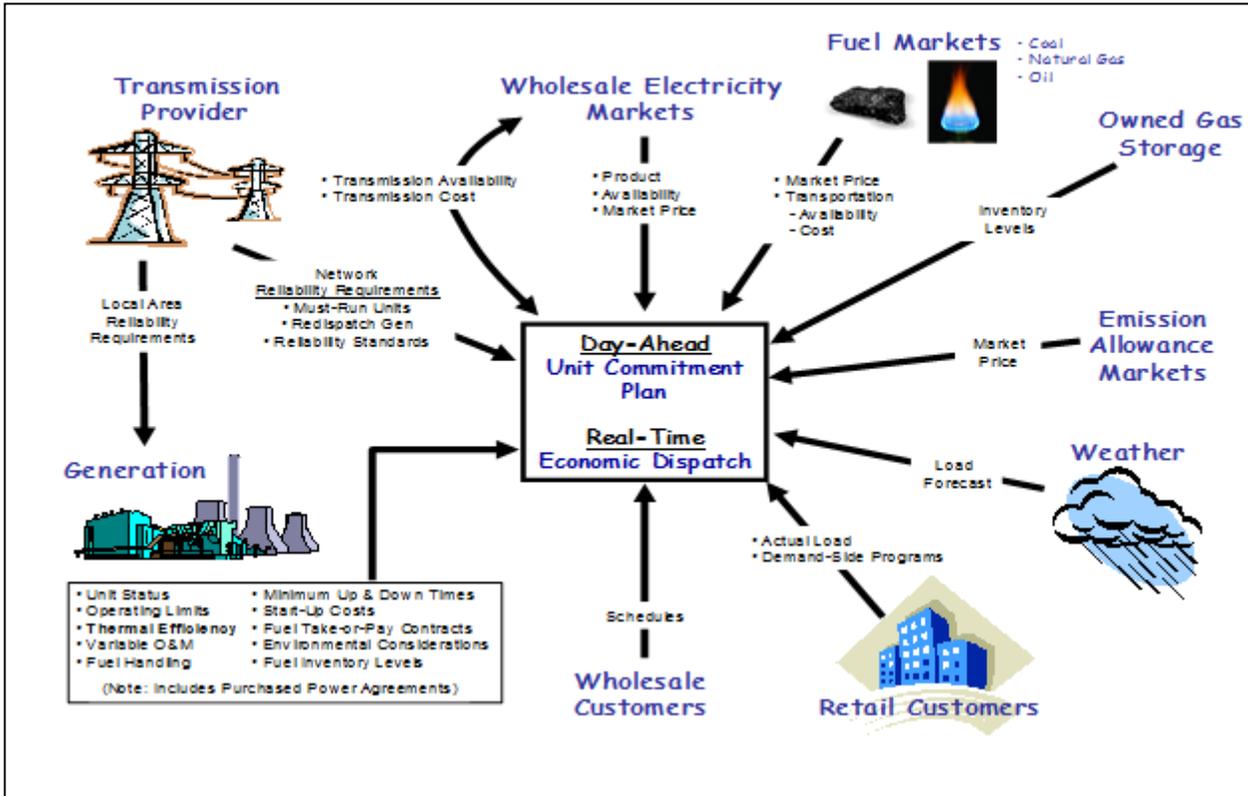
¹⁴ <http://publicpower.com/2013/7606/>

¹⁵ The overall resource optimization process begins with integrated resource planning as described previously. The operating companies then utilize these resources in the unit commitment process.

markets is summarized in Figure 2. How these complex processes work is described in detail below.

Figure 2.

Optimizing Assets through the Economic Dispatch Process



Unit Commitment

In bilateral markets, utilities typically develop a unit commitment plan to optimize the use of available generation resources to economically and reliably serve their customers. The unit commitment plan identifies the generation resources to be committed for economic dispatch during the next day. The generation resources are selected from available resources (including purchased power opportunities) such that total production cost to serve the expected load is minimized, taking into account any transmission constraints, environmental requirements, fuel supply constraints or other limitations shown in Figure 2.

As part of the unit commitment process, the utility will constantly seek wholesale purchase opportunities. Most utilities operating in bilateral markets employ teams of term and hourly traders that thoroughly canvass the wholesale markets for beneficial power purchases (or to make third-party sales when surplus power is available). Term traders seek offers for purchases from wholesale market participants at prices that are expected to reduce the total cost to serve

load over the given term. The duration of these term transactions is typically for a portion of the next day, but can range up to one year. The desired term of a purchase is a function of load shape, ramp rates, and other system conditions. The desirability of a particular purchase often depends on the flexibility offered in products and terms to achieve economical operations.

Utilities will use all available means to transact in the markets, including telephone, the Inter-Continental Exchange on-line trading platform, other trading platforms, and voice brokers in order to let market participants know which products they seek to incorporate into their unit commitment process. Once apprised of a utility's request to purchase power, market participants submit offer prices that would be profitable for them while still remaining economical for possible selection by the purchasing utility. The price offered also depends on whether the seller has market-based pricing authority from FERC, or whether the offer must be cost-based.

If a market participant is offering energy at a price that will reduce the utility's production costs, then that utility's traders will attempt to negotiate a purchase. If successful, such a purchase will be scheduled and subsequently incorporated into the unit commitment and real-time economic dispatch processes. The result is that term purchases from non-utility generators and other market participants affect both unit commitment and ultimately economic dispatch by displacing more expensive generating resources. Considerable savings can result from this process.

In making unit commitment decisions to select resources from those available (including purchases), the utility must consider a variety of factors as shown in Figure 2, including:

1. Weather conditions and their impact on forecasted load, hydroelectric status, and unit operations;
2. Variable costs incurred in the production of electricity. Variable cost components include:
 - a. Thermal efficiency (*i.e.*, heat rate),
 - b. Fuel costs, including associated transportation costs,
 - c. In-plant fuel handling expenses,
 - d. Variable operations and maintenance expenses,
 - e. Emission allowance replacement costs, and
 - f. Transmission losses;
3. Power, fuel, and emissions markets;
4. Transmission availability and costs associated with purchases;
5. Operating characteristics and limits of generation facilities:
 - a. Minimum and maximum operating limits,¹⁶
 - b. Ramp time,¹⁷
 - c. Cycle times,¹⁸

¹⁶ A minimum operating limit is the lowest level of output that can be achieved without resulting in possible harm to the generating unit; likewise, a maximum operating limit is the highest level of output that can be achieved without resulting in possible harm to the generating unit.

¹⁷ Ramp time is the amount of time it takes an out of service generator to come online or to go from one output level to another level.

¹⁸ Cycle times are both the minimum amount of time the generating unit must be allowed to operate once connected to the network (sometimes referred to as minimum up-time) and the minimum amount of time the unit must be allowed to stay off-line once decommitted (sometimes referred to as minimum down-time).

- d. Compliance with environmental requirements,
 - e. Start-up costs (*i.e.*, the costs to bring the generating unit on-line), and
 - f. Fuel inventory levels;¹⁹
6. Known operational limits of transmission facilities;
 7. Availability of demand-side resources and costs;
 8. Reliability standards; and
 9. State and federal regulatory requirements, including environmental limitations on any resources.

Real-Time Dispatch

Once the unit commitment and term power purchase decisions are made, then the real-time economic dispatch process determines the optimal output levels of each dispatchable resource in real-time, based on the marginal costs of each resource using well-established and industry-accepted methodologies. The marginal cost components in the economic dispatch process include the generating resource heat rates (*i.e.*, thermal efficiency), commodity cost of fuel, fuel transportation costs, fuel-handling expenses, variable operations and maintenance expenses, emission allowance costs, and transmission losses. No fixed costs are considered.

In addition to utilizing the units selected through the unit commitment process, utilities typically employ hourly traders to seek offers for next-hour purchases from wholesale market participants so as to reduce the hourly marginal cost to serve load. If an economic hourly purchase is made, then committed units are backed down for the following hour in an amount equal to the power being purchased. In this way, the utility is assured that the least-cost available resources are being used in each hour. These hourly traders also make hourly purchase (or sales) decisions to manage deficits arising as a result of deviations between projections used in the unit commitment process and the actual system conditions in real-time.

In real-time, a utility's Energy Management System utilizes a resource balancing algorithm that measures generation and load balance of the utility's electric system to meet the customers' real-time needs (the rapid nature of changes in utility load would make manual operation of the system close to impossible). This automated process captures system load demand, downward-and-upward regulating margin requirements, lower and upper operational limits of each generating unit, maximum ramping rate of each generating unit, and each unit's incremental heat rate. It also automatically adjusts the output of the generating units that are operating on the margin to meet the instantaneous changes of load on the system. The automatic output adjustment is accomplished by means of an automatic generation control ("AGC") system installed on certain generating units capable of fast reaction.

Merchant generators have sometimes argued that economic dispatch is a "monopoly" function that gives vertically-integrated utilities in bilateral markets an unfair advantage. These arguments ignore the fundamental requirements of economic dispatch within vertically-

¹⁹ If fuel inventory levels are too high, it may be economic to dispatch the generating unit "out-of-cost" to reduce fuel inventory; however, if inventory levels are too low, it may be economic to decommit the generating unit "out-of-cost" to increase fuel inventory.

integrated utilities in bilateral markets that would make direct participation in economic dispatch (as opposed to bilateral sales into the dispatch process) unattractive to merchant generators. First, as previously discussed, to ensure that customers receive the least costly mix of resources feasible, economic dispatch in vertically-integrated utilities is done based on costs. Third parties interested in being dispatched would have to provide their cost information to the dispatching utility and be dispatched based on cost. Payments for the capacity they provide would be available only if they entered into a long-term purchased power agreement with one of the operating companies as part of the resource planning and acquisition process.

Secondly, AGC is required on plants that are to be dispatched. Most merchant plants do not have AGC equipment which can be costly.

Third, and perhaps most importantly, participants in most pooling arrangements are required to make themselves available at all times, under the terms of the pooling agreement or contract. Thus, a merchant generator that wanted to participate in a pool's dispatch could not make outside sales when the economics were better, and might have to shut down when called upon to do so by the system dispatcher. All of these are requirements of generators participating in most pools, but would not be acceptable to third parties wishing to sell into (or buy from) the pool on a regular basis. Nor would direct inclusion in dispatch necessarily result in more merchant generation being utilized. Simply including such generators in dispatch would do nothing to change their fundamental economics. If merchant generators are bidding at or near their marginal costs, and those costs are competitive with the dispatching utility's costs, then there would be no difference in the utilization of these assets.

From time to time there are complaints that vertically-integrated utilities do not buy from merchant generators even when they offer prices below the cost of the utilities' own generation. But the fact is there is no economic incentive or rationale for a utility to refuse to purchase cheaper energy in the market instead of dispatching its own resources. Utilities in regulated markets collect their fixed costs through either a retail or wholesale rate base. In fact, where utilities have an obligation to serve all existing and future customers in a defined service area, they have a right to recover the prudently incurred costs of meeting their service obligations. But once fixed costs are put in rate base, the utility's incentive is to use the cheapest generation possible, within reliability and security constraints. They make no money on fuel costs (and in fact, if fuel costs are increasing, they may lose money between rate cases or fuel cost reviews). Thus, they have no incentive to run their own units if cheaper, third party power is available in the wholesale market.

There are also regulatory mechanisms in place to ensure that utilities do indeed use the least-cost resources available. States continually review the fuel and power purchases and use of their jurisdictional utilities, either in the context of fuel surcharge reviews or in general rate cases. If the state regulatory authority determines that a utility is running its own units when lower cost power is available on the market, they will deem such decisions to be imprudent and disallow fuel costs. This strengthens the incentives that utilities have to take advantage of all known market opportunities in the resource optimization process.

There have also been calls for vertically-integrated utilities to change their dispatch procedures in other ways. In the context of FERC's OATT Reform rulemaking that resulted in FERC Order 890, there were at least three proposals for FERC to mandate an open dispatch function which would, in one way or another, result in bilateral markets looking more like centralized markets. These proposals include a filing by Professor Bill Hogan and John Chandley,²⁰ a proposal for "open dispatch" by PJM,²¹ and a proposal for "transparent dispatch" by a group calling itself "Transparent Dispatch Advocates (TDA)".²²

These proposals have common themes: (i) the accusation that there is still undue discrimination in wholesale markets that results from vertical integration and a preference for native load customers; (ii) the claim that the only solutions are to require such utilities to open their dispatch to third parties on a regional basis, and to redispatch their systems on request to provide transmission service when there is insufficient transmission capacity; and (iii) the claim that seams issues between centralized and bilateral markets make it essential that all markets be centralized. However, there are some differences as well. At its core, PJM was essentially advocating to impose their full LMP model nationwide. Hogan/Chandley and TDA argued that something short of full LMP markets would be possible. TDA also emphasizes the need for utilities to publish their real-time costs so that redispatch costs can be estimated in advance.

The proposition behind all of these proposals was that the current methods for providing transmission service and dispatch in vertically-integrated utilities are inherently unduly discriminatory or preferential. Despite unfounded speculation to the contrary, utility commitment and dispatch processes, as described above, specifically consider purchases from third parties and routinely make wholesale purchases from them when they offer products that (i) customers need; (ii) are at a price that reduces the utility's costs; and (iii) can be transacted within reliability constraints. The current economic dispatch procedures used in bilateral markets, as well as oversight by state commissions, ensure that the utility's native load (retail and wholesale requirements) customers get the best deal reasonably possible. And the Energy Policy Act of 2005 made it perfectly clear that the use of the transmission system to serve native load customers first is not unduly discriminatory or preferential.²³ Thus, the claims of discrimination made by supporters of "open" and "transparent" dispatch are based upon a faulty premise.

In addition to calls for "open" or "transparent" dispatch, merchant generators in the past have also sought to mandate, through federal legislation or regulation, something they call "efficient" dispatch. Advocates of efficient dispatch argue that plants should be dispatched based on thermal efficiency²⁴. Since gas plants are more thermally efficient than coal or nuclear plants, efficient dispatch would mean that gas-fueled plants get dispatched before coal or nuclear-fueled

²⁰ John D. Chandley and William W. Hogan, A Path to Preventing Undue Discrimination and Preference in Transmission Services, FERC Dockets Nos. RM05-25, RM05-17 (filed August 2, 2006).

²¹ Comments of PJM Interconnection, LLC, FERC Docket Nos. RM05-25, RM05-17 (filed August 7, 2006).

²² Reply Comments of PJM Interconnection, LLC, et al, FERC Docket Nos. RM05-25, RM05-17 (filed September 20, 2006).

²³ 16 U.S.C. § 824q(k).

²⁴ Thermal efficiency (sometimes referred to as heat rate) is the amount of fuel input it takes to produce the next increment of power output. It is usually measured in terms of Btu/KWH. The lower the thermal efficiency, the more efficient a generating resource is said to be.

plants. Since the preponderance of merchant-owned generation is gas-fired, it is not surprising why they would make this argument. “Efficient” dispatch is not the same as “economic” dispatch. In fact, efficient dispatch can often result in uneconomic dispatch that leads to higher electricity prices for consumers. The most efficient gas-fired generating plants do not necessarily provide the lowest-cost power to consumers. Different types of generating plants have differing operating features that are important in determining when they are used. These include thermal efficiency, short-term fuel costs, emission rates, and start-up times, among others. It is not possible to decide which plant is the best to operate by looking only at thermal efficiency or even marginal cost, and it is often the case that the goals of dispatching plants with the greatest level of thermal efficiency and dispatching the lowest-cost available power to consumers are incompatible.

Advocates of centralized markets also argue that such markets have a broader geographical reach and therefore optimize the dispatch of generation over a larger region. But the geographical area for which economic dispatch occurs is totally unrelated to the market structure. Bilateral markets often incorporate economic dispatch over even broader geographic areas than do centralized markets. For example, Southern Company in the Southeast encompasses a larger geographic area for its dispatch than several of the ISOs/RTOs. Thus, the presence of a centralized market does not equate to a larger area or market for economic dispatch than for bilateral markets. The optimal and proper size for a dispatch region depends on many factors, including topography of the transmission systems, costs versus benefits of wider areas, and critically – regulation by State PUCs, which will want to ensure that the dispatch area is optimizing service for their own jurisdictional customers.

Importantly, the Energy Policy Act of 2005 set up two processes to study the subject of regional economic dispatch – the first required a study by DOE, and the second established joint boards between FERC and the States to study the issues on a regional basis. Both of these processes have been completed, and their conclusions suggest that economic dispatch is working well and that there is no basis to require radical changes.

Transmission-Related Considerations in Economic Dispatch

A utility’s unit commitment and economic dispatch processes are subject to redispatch orders from the transmission provider (which may or may not be the same, or affiliated with the same entity as the dispatching utility) to address transmission reliability constraints. Such orders may include the dispatch of “must-run” generation for reliability purposes. For example, if the transmission provider determines that a particular generating unit’s output is needed to provide voltage support, then such unit will operate regardless of its marginal costs.

Additionally, a generating resource’s physical location on the transmission system can have an impact on its commitment and operation. Each dispatching utility that is also a North American Electric Reliability Corporation (NERC) Balancing Authority is responsible for maintaining a safe and reliable network by tracking unit commitment plans, actual generation operation, and all transmission schedules across, into, and out of the control area. In order to achieve this, a utility’s transmission business unit or its unaffiliated transmission provider sometimes requires changes to unit commitment, generation operation and transmission schedules to address: (1)

transmission congestion; (2) transmission interface capabilities; (3) operating reserve margins; and (4) voltage or stability concerns. This is the “security” part of security constrained economic dispatch.

All of the foregoing processes (*i.e.*, unit commitment, real-time economic dispatch, and consideration of transmission-related security issues) ensure that the utility’s native load customers are served at the lowest possible cost during each hour of the day, given real-time operational and reliability limitations.

Economic Dispatch in Centralized Markets

Interestingly, the formal process for conducting economic dispatch in the centralized markets does not differ significantly from the process in bilateral markets with vertically-integrated utilities. The objectives are still the same. The only major difference is that unit commitment in centralized markets is done based on day-ahead bids, and real-time dispatch is done based on hourly bids, rather than a combination of costs and bids in the bilateral markets. There is a formal process for collecting bids which differs from the process for getting bids in bilateral markets, but there is no evidence to suggest that one is more efficient than another.

But while there is no real technical difference in how dispatch operates, the fact that unit commitment and real-time dispatch is based on bids rather than costs, and that all generators receive the locational market-clearing price can make a big difference. In the bilateral markets bids from third parties are compared against actual marginal generating costs to determine what resource to use. Thus customers can be assured that they are getting the least-cost mix of resources (subject to reliability constraints) available in each hour. In centralized markets, market bids are being compared against market bids, so that there is no assurance that the least-cost mix of resources is being used. In theory, all generators in a centralized market should be bidding their actual marginal costs, in which case the bilateral and centralized markets would have the same result. But particularly in times of scarcity, the price of power is likely to be bid up above the marginal cost of the highest cost generator – as it should be as an incentive for someone to go out and build additional capacity. And if there is any market power within the centralized markets, bids will also be above marginal costs. Thus, while theory suggests that bilateral and centralized markets would result in the same dispatch (all else being equal), there are real-world factors which could certainly cause centralized markets to have a higher cost dispatch. Absent studies about the efficiency of dispatch in the two market types, it is difficult to reach conclusions about the relative efficiency of short-term markets.

Transparency Issues

Generation

Advocates of centralized markets argue that transparency in such markets result in additional efficiencies that are not available in bilateral markets. Or they argue that because of the lack of transparency, there is no way to know whether traditionally-regulated utilities are indeed operating efficiently and using the lowest cost resources available, whether owned by them or someone else. They also argue that lack of transparency in transmission service prevents them from being assured that transmission is being provided in a non-discriminatory manner. As discussed below, the kinds of transparency being advocated would be detrimental to retail customers, and are not necessary to ensure fair and efficient operation of competitive bilateral wholesale markets.

One argument frequently made by merchant generators is that more information be publicly posted about offers to sell that were accepted or rejected by the vertically-integrated utility, and why. They believe that such information would result in more liquid and competitive markets. This is not the case. First and foremost, publishing data regarding offers would likely change the offer patterns of generators. They would have little incentive to offer prices below the published prices. And significant data is available from multiple sources that has been aggregated so that individual transactions are masked.

Second, in order for publication of offers to be meaningful, standardized market products would have to be adopted. However, the uniform adoption of such standard products would harm retail customers, because such products are not flexible enough to meet their needs. For instance, it could be more economical for a utility to start up a combustion turbine generator for only two hours of peak load, rather than to purchase a standard 16-hour product. Because many utilities consistently utilize flexible purchases that are by definition non-standard, the public reporting of prices for these individual transactions could be misleading to sellers.

Third, in locational marginal pricing (“LMP”) markets, the market-clearing price is what is transparent – not any individual offers or utility cost data. However, in regions that do not have a centralized bidding market, there usually is no well-established market-clearing price available. The publication of individual offers (even winning offers) or utility costs would be contrary to the interest of consumers and competitors, as discussed above. Having said that, however, there are private reporting services (such as ICE and others) that provide market price information in the same form as that available in centralized markets – to the extent that standard products are traded in the bilateral markets.

Transmission

Some merchant generators complain that there is also a lack of transparency regarding transmission. In some cases these complaints relate to Transmission Loading Relief (TLR) procedures where the dispatcher is required to cut or cancel a transaction due to an unforeseen contingency in operation of the system. In other cases, merchant generators believe they are denied transmission service for reasons that are not transparent to them. And finally, there have been complaints that the calculation of Total Available Transmission Capacity (TTC) and Available Transmission Capacity (ATC) is a black box that they don’t understand and is inconsistent across the country.

In fact, there is significant transparency in transmission operations, as a vast amount of transmission information is posted on OASIS, the electronic bulletin board that all jurisdictional transmission providers were required to establish under FERC Orders 888 and 889, including information pertaining to TTC, ATC, and transmission studies.²⁵ Moreover, should a customer's transmission request be denied, not only does the reason for the denial have to be posted on OASIS, but "[i]nformation to support the reason for the denial, including the operating status of relevant facilities, must be maintained for 60 days and provided upon request, to the potential Transmission Customer."²⁶ Likewise, and contrary to the generators' assertions, should a curtailment (TLR) be called, not only does the transmission provider have to post notice and reason for the curtailment, but the transmission provider also has to maintain information supporting any such curtailment, "including the operating status of the facilities involved in the constraint or interruption", and that information must be "made available upon request, to the curtailed...customer, the FERC's Staff, and any other person who requests it, for three years."²⁷

Utilities in bilateral markets plan and build their transmission systems to meet the needs of their native load customers and requests for long-term firm transmission service. In many cases, the reason a particular transaction is curtailed is because the transmission service customer preferred not to enter into such a long-term firm agreement, possibly because transmission studies demonstrated that additional facilities would be needed. This fact means that a generating facility that is not the source for a long-term firm transmission agreement should not expect to be able to run without experiencing transmission limitations. Furthermore, absent participant funding or direct assignment of costs, building-out the transmission system so that all generators within the system can always be incorporated into economic dispatch would be prohibitively expensive and place an undue burden on retail customers. Unless those costs were participant funded or directly assigned to the generators, building out the transmission system would force retail customers to subsidize the generators, who would receive the benefits of greater access to markets without having to bear the associated costs. This subsidization problem would be especially profound in instances where the generator has made a relatively poor siting decision and located its generator in a transmission constrained location.

Order 890, issued by the FERC in February 2007 contains additional transparency provisions, especially as they relate to information posted regarding transmission capacity availability. The Order also sets in place a process to look at potential standards for increased consistency in TTC and ATC calculations across the country. Order 890's additional provisions, combined with the information already available and rules governing that information should be more than sufficient to assure generation developers and regulators that proper and accurate transmission information is being provided.

Bilateral Markets are Working

²⁵ See 18 C.F.R. § 37.6 ("Information to be posted on the OASIS"); Order No. 605, 87 FERC ¶ 61,224 (1999).

²⁶ *Id.*

²⁷ *Id.*

While participants in bilateral markets are not pushing to “undo” centralized markets, require vertical re-integration, or return to cost-based wholesale rate regulation, they do generally believe that the vertically-integrated utility model, with traditional state retail regulation and competitive bilateral wholesale markets provides numerous benefits that are not readily apparent in the centralized markets. Specifically, the traditional model ensures:

- reasonable and stable prices;
- assurance of an adequate supply from diverse fuel sources;
- ability to plan the system in an integrated fashion, ensuring the lowest overall costs of investment decisions;
- a shorter-term wholesale market to provide optimization opportunities – both purchases and sales
- economies of scope through operating an integrated system; and
- clear lines of accountability.

With respect to retail prices, the rates of customers residing in bilateral markets are generally among the lowest in the country. Although rising and falling natural gas costs have affected retail rate volatility in both centralized and bilateral markets, fuel diversity has been an important factor in mitigating the adverse effects of natural gas price levels and volatility in bilateral markets. In centralized markets, in contrast, the price of all energy tends to rise to the marginal cost of gas or oil-fired generation (or even coal in some cases) in many hours of the year. This means that even if nuclear power is producing a substantial proportion of the energy required in any of these hours, wholesale prices are still based on the costs of gas, or coal. There is no doubt that this market structure results at least in the short-term, in higher and more volatile prices for consumers than would be the case in a traditional regulated environment. The polar vortex of January and February 2014 provided ample evidence of these differences.

The problem is exacerbated by the fact that practically all generation that has been constructed in centralized markets in the past decade has been natural-gas fired, and there is no indication that any additional base-load coal or nuclear plants are going to be built in the near future. As centralized markets become reliant on natural gas at the margin in even more hours of the year, energy produced by the remaining coal and nuclear plants in those regions will become more expensive to consumers, even as they become fully depreciated. And every time the price of natural gas changes in those markets, so too will the price of energy produced by coal and nuclear facilities, even though the costs of energy produced by coal and nuclear may not be changing in the same manner or to the same degree.

The traditional bilateral markets model, on the other hand, has been very successful in keeping rates low and stable. Retail rates are based on actual costs in these markets and not on the vagaries of the hourly spot market. Contributing to the overall success of the vertically-integrated, bilateral model is the fact that wholesale competition in such regions is largely predicated on long-term bilateral contracts – an option that has generally not been available in centralized markets.²⁸ One of the primary benefits of long-term contracts is that they provide a financially stable market, including financially stable competitors, from which short-term liquidity (in the form of asset optimization) is achieved. Long-term contracts in these cases are a

²⁸ American Public Power Association, op. cit.

product of both formal competitive bidding processes and bilateral negotiation where load serving entities select for themselves (with appropriate regulatory oversight) the best generation resources (and mix of fuels) to meet their requirements. For utilities in bilateral markets, these resource solicitation and selection processes are most often subject to state regulatory review, and resulting wholesale sales contracts are also subject to FERC review.

The continued use of integrated resource planning has also contributed to the success of bilateral markets. In centralized markets, generation and transmission planning is not well coordinated. Accordingly, the resulting generation location decisions or transmission investment decisions often are not optimal from either an efficiency or total cost perspective. In the vertically-integrated model, utilities are able to consider and evaluate generation, transmission, distribution, and demand side decisions together when they decide whether to buy or build, and where to locate generation to minimize overall costs for customers.

By virtue of the traditional business model, vertically-integrated utilities are also able to take advantage of economies of scope – that is, to operate generation, transmission and distribution in a coordinated manner to provide least-cost solutions. The Cato Institute study mentioned earlier points to such economies of scope as one of the critical factors overlooked when many States and regions required divestiture of either generation or transmission.²⁹

The ability to operate as an integrated system also ensures that there are clear lines of accountability for ensuring reliability, both in the short-term and the long-term. Vertically-integrated utilities in bilateral markets have an obligation to provide reliable service to all customers in their franchised service areas, and take that obligation seriously. Where utilities are not vertically-integrated, the responsibility for transmission system reliability is divided between the participating utilities and their RTO or ISO making coordination more difficult. And because there is typically no service obligation, the responsibility for assuring sufficient transmission and generation assets is also diffuse.

Vertically-integrated utilities with franchise service obligations have a special commitment to the communities they serve. It is in the best interest of both the communities and the utility to work together to promote economic development and the social well-being of the community. Again, because they have some assurance of cost recovery, vertically-integrated utilities are more likely and willing to engage in community activities. In fact, this is why so many of them are known as “public service” companies. They recognize that by having a franchise to do business in a community, certain responsibilities are conveyed with that franchise – responsibilities which are not as clear when utilities are participating in centralized markets, particularly where suppliers are competing for retail customers.

Finally, and perhaps most importantly, customers are satisfied with the results of the vertically integrated/bilateral wholesale market business model. Of the top 15 companies comprising the Large Utility Segment in the most recent J.D. Power survey of residential customer satisfaction, 14 of them are vertically-integrated and 11 of those vertically-integrated companies operate in bilateral markets with traditional cost-of-service regulation.³⁰

²⁹ Robert J. Michaels, *op. cit.*

³⁰ J.D. Power 2015 Electric Utility Residential Customer Satisfaction StudySM, July 15, 2015 Press Release.

Conclusions

Now that the nation has had about 20 years of experience with centralized LMP markets, it is appropriate to take a step back and see what is – and what is not -- working in both centralized LMP markets and traditional bilateral wholesale markets. It is clear that there is a growing belief that centralized markets have some issues they need to address, and there are elements of bilateral markets that can be improved as well. Policymakers at both the state and Federal levels should adhere to basic principles that apply to all competitive wholesale markets as changes to these markets are contemplated:

- Competition should be a means to an end, not the end itself. The goal should always be to ensure reliable service to customers at the lowest practicable cost;
- The benefits of wholesale competition can only be achieved through a strong working relationship between the Federal and state regulators;
- Competitive market rules should not favor one corporate structure, business model, or retail regulatory regime over another. There are many different models that can deliver on the policy goal of using efficient competitive wholesale markets to ensure customers reliable service at the lowest possible cost;
- Price signals for generation and transmission in competitive wholesale markets should promote efficiency and avoid subsidies between and among customers and suppliers; and
- Ensuring resource adequacy and reliability are absolutely critical in both centralized and bilateral wholesale markets, and should be the primary focus of policy deliberations.

Wholesale competition seems to be working quite well in bilateral markets. These markets have a demonstrated record of building infrastructure to meet the needs of retail and wholesale customers and transmission users in utility service areas, and with oversight by FERC and state commissions; bilateral markets are working well. Retail prices have remained well below those of centralized markets as well. There is no evidence that implementing centralized LMP markets or some hybrid of bilateral and centralized markets would be beneficial to customers in these markets. The current traditional structure has served consumers well, and can and will continue to do so well into the future.