Principles for Efficient and Reliable

Reactive Power Supply and Consumption

Table of Contents

Preface

In August 2003, there was a widespread power outage that affected 50 million people in the United States and Canada. As a result of the April 2004 report and recommendations of the U.S.-Canada Power System Outage Task Force and an increased number of filings for reactive power compensation at the Commission, Chairman Pat Wood III formed an interoffice staff team to develop principles for efficient and reliable reactive power supply and consumption.

The team consisted of Richard O'Neill (team lead), Mary Cain, David Mead, Derek Bandera, David Withnell, Zolaikha Salihi, Dharmendra Sharma, Emily Bartholomew, Giuseppe Fina, Harry Singh, Kumar Agarwal, Tomohisa Koyama and Victor Coulter. John Jennrich served as editor. Judy Eastwood served as graphic artist.

Brendan Kirby, John Kueck, Chris Mak, Frank Macedo, Ross Baldick, Bill Stewart. Marija Ilic, Jamie Weber, Oscar Muñoz, Bruce Poole, Gary Nakarado, Saeed Farrokhpay, Thanh Luong, LaChelle Brooks, Thomas Dautel, Kevin Kelly, James Ballard, Vis Tekumalla and Joe McClelland, among others, provided helpful comments and contributions.

Over several months, team members consulted representatives of the American Public Power Association, Edison Electric Institute, Electric Power Supply Association, Institute of Electrical and Electronics Engineers, National Association of Regulatory Utility Commissioners, North American Electric Reliability Council, regional transmission organizations and various equipment manufacturers.

This report contains analyses, presentations and conclusions that may be based on or derived from the data sources cited, but do not necessarily reflect the positions or recommendations of the data providers.

The team appreciates the many contributions it has received. Any errors are those of the interoffice staff.

EXECUTIVE SUMMARY

Principles for Efficient and Reliable Reactive Power Supply and Consumption

Almost all bulk electric power in the United States is generated, transported and consumed in an alternating current (AC) network. Elements of AC systems produce and consume two kinds of power: real power (measured in watts) and reactive power (measured in volt-amperes reactive, or var). Real power accomplishes useful work (e.g., running motors and lighting lamps). Reactive power supports the voltages that must be controlled for system reliability.

Reactive power supply is essential for reliably operating the electric transmission system. Inadequate reactive power has led to voltage collapses and has been a major cause of several recent major power outages worldwide. And while the August 2003 blackout in the United States and Canada was not due to a voltage collapse as that term has been traditionally used, the final report of the U.S.-Canada Power System Outage Task Force (April 2004) said that "insufficient reactive power was an issue in the blackout." Dynamic capacitive reactive power supplies were exhausted in the period leading up to the blackout.

Sound regulatory policies are necessary to ensure an adequate supply of reactive power at reasonable cost. The rules for procuring reactive power can affect whether adequate reactive power supply is available, as well as whether the supply is procured efficiently from the most reliable and lowest-cost sources. This is readily apparent in the large portions of the United States where the grid is operated by independent system operators (ISOs); these operators do not own generation and transmission facilities for

producing and consuming reactive power, and therefore must procure reactive power from others. But procurement rules also affect other parts of the United States where vertically integrated utilities operate the grid, because reactive power capability also is available from independent companies. Sound policy would ensure that system operators – whether they are independent or vertically integrated – have adequate reactive power supplies to choose from and at the lowest reasonable cost.

Not only is reactive power necessary to operate the transmission system reliably, but it can also substantially improve the efficiency with which real power is delivered to customers. Increasing reactive power production at certain locations (usually near a load center) can sometimes alleviate transmission constraints and allow cheaper real power to be delivered into a load pocket. Regulatory policies can substantially affect whether reactive power is supplied so as to provide these economic benefits.

There are several problems and concerns regarding the current procurement practices and pricing policies for reactive power:

1. Discriminatory compensation.
   a. Transmission-based suppliers of reactive power capability receive compensation, yet many generation-based suppliers are not compensated for reactive power capability that aids in system reliability.
   b. Independent generation resources may not always be compensated for providing reactive power support to the grid in areas where other generators affiliated with vertically integrated transmission owners receive cost-of-service payments for providing similar service, despite the Commission's policy requiring comparability.

2. Rigid but imprecise interconnection standards that are insensitive to local needs.
Interconnection standards generally require a standardized generation power factor for new generation. But local needs often vary from the standards. Some locations may have higher reactive power needs than the standard, while other locations may have smaller needs. Moreover, the standards are imprecise in important respects. For example, the standards do not specify on which side of the step-up transformer, and exactly how, the power factor is to be measured.

3. Lack of transparency and consistency in planning and procurement.

The reactive power planning standards and procurement processes are not transparent. Alternative solutions to provide needed reactive power capability may be available, but currently these options might not be adequately considered.

4. Poor financial incentives to provide or consume reactive power.

a. Many market participants that could provide additional reactive power capability to the system have little incentive to do so. Price signals that could encourage additional investment are limited.

b. In many cases load response and load-side investment could reduce the need for reactive power capability in the system, but incentives to encourage efficient participation by load are limited.

5. Poor incentives for some system operators to procure reactive power and reactive power capability at least cost.

System operators outside of regional transmission organizations (RTOs) and ISOs that are regulated transmission owners may lack the incentives to consider all available sources of reactive power. That is because cost-of-service regulation generally rewards capital investment, even when purchasing from a third party would be a less costly alternative.

6. Failure of system operators to adjust reactive power instructions so as to fully optimize the dispatch.

Often, a range of reactive power production levels would fully meet the reliability requirements of a transmission system. However, system operators typically choose the level that meets specified guidelines, even though other levels within the range would allow the demands for real power to be met at a lower total cost. A related issue is that the software for implementing such reactive power optimization is not currently available.

The purpose of this paper is to begin a discussion about the proper regulatory policy toward reactive power pricing and market design. First, it examines the physical characteristics and costs of producing reactive power. Second, it reviews the history of reactive power pricing at the Commission and briefly discusses current practices in other countries. Finally, it develops pricing principles and examines market designs for reactive power. The paper

also includes appendices that address the more technical issues in modeling reactive power market design. To address the six problems and concerns identified above, the paper makes four broad recommendations:

1. Reactive power reliability needs should be assessed locally, based on clear national standards.
2. These needs should be procured in an efficient and reliable manner.
3. Those who benefit from the reactive power should be charged for it.
4. All providers of reactive power should be paid, and on a nondiscriminatory basis.

It may also be helpful to clarify what this paper does not do. It does not advocate an unregulated market for reactive power, since market power problems could be widespread in reactive power supply. It does not advocate a national prescribed approach to reactive power needs. It does not intrude on the responsibilities of the North American Electric Reliability Council (NERC). It does not advocate a specific technology approach; it is technology neutral. And it does not advocate abrogating existing contracts.

Physical characteristics and costs. Reactive power may be supplied by several different sources, including transmission equipment (such as capacitors, reactors, static var compensators and static compensators), generators and synchronous condensers. Reactive power does not travel over long distances at high line loadings due to significant losses on the wires. Thus, reactive power usually must be procured from suppliers near where it is needed. This factor limits the geographic scope of the reactive power market and, thus, the number of suppliers that can provide reactive power and the amount of competition at any place and time, at least in the short term before other suppliers can enter the market.

But while competition may be limited in reactive power markets, there may be at least some existing alternative sources of reactive power supply in many locations, and new sources may be able to enter the market over the longer term. The goal should be to develop rules that ensure that adequate supplies of reactive power (including reactive reserves) are available in all locations to ensure that operation of the grid is reliable and efficient and that reactive power is procured at least cost over the short and long run. As we discuss below, transparent and nondiscriminatory markets and prices for reactive power have the potential to promote this goal.

Generally, reactive power support is divided into two categories: static and dynamic. Static reactive power is produced from equipment that, when connected to the system, cannot quickly change the reactive power level as long as the voltage level remains constant, and its reactive power production level drops when the voltage level drops. Capacitors and inductors supply and consume static reactive power. Dynamic reactive power is produced from equipment that can quickly change the Mvar level independent of the voltage level. Thus, the equipment can increase its reactive power production level when voltage drops and prevent a voltage collapse. Static var compensators, synchronous condensers and generators provide dynamic reactive power.

Both the variable and fixed costs of producing static reactive power are much lower than those of producing dynamic reactive power. If cost were the only issue, a transmission provider at any instant in time would use static reactive power equipment first in procuring reactive power, and use the dynamic equipment only after the static equipment had been fully used. However, two factors force transmission providers at times to use more expensive dynamic reactive power sources in place of cheaper sources. First, the lowest cost sources cannot always produce reactive power as reliably as necessary. Static power equipment does not produce reactive power as reliably as dynamic power equipment because the transmission equipment's production depends on voltage and, thus, its ability to produce declines when voltage declines. Second, because reactive power does not travel far (due to significant transmission losses), it usually must be produced near the location where it is needed. Thus, expensive reactive power sources must sometimes be purchased even if cheaper sources are idle because the expensive source is more reliable and/or is near the location needing the reactive power, while the cheaper sources cannot get the reactive power to where it is needed.

A generator's cost of producing reactive power can sometimes include opportunity costs associated with forgone real power production. Opportunity costs arise because there can be a trade-off between the amount of reactive power and real power that a generator can produce. When a generator is operating at certain limits, a generator can increase its production or consumption of reactive power only by reducing its production of real power. As a result, producing additional reactive power results in reduced revenues associated with reduced real-power production.

The history of reactive power pricing at the Commission. The recent history of reactive power pricing begins with the Commission's Order No. 888, its Open Access Rule, issued in April 1996. In that order, the Commission concluded that "reactive supply and voltage control from generation sources" is one of six ancillary services that transmission providers must include in an open access transmission tariff. The Commission noted that there are two ways of supplying reactive power and controlling voltage: (1) installing facilities as part of the transmission system and (2) using generation facilities. The Commission concluded that the costs of the first would be recovered as part of the cost of basic transmission service and, thus, would not be a separate ancillary service. The second (using generation facilities) would be considered a separate ancillary service and must be unbundled from basic transmission service. In the absence of proof that the generation seller lacks market power in providing reactive power, rates for this ancillary service should be cost-based and established as price caps, from which transmission providers may offer a discount.

In Opinion No. 440, the Commission approved a method presented by American Electric Power Service Corp. (AEP) for generators to recover costs for reactive power. AEP identified three components of a generation plant related to the production of reactive power: (1) the generator and its exciter, (2) accessory electric equipment that supports the operation of the generator-exciter, and (3) the remaining total production investment required to provide real power and operate the exciter. Because these plant items produce both real and reactive power, AEP developed an allocation factor to sort the annual revenue requirements of these components between real and reactive power production. The factor for allocating to reactive power is $Mvar^2/MVA^2$, where Mvar is megavolt amperes reactive and MVA is megavolt amperes. Subsequently, the Commission indicated that all generators that have actual cost data should use this AEP method in seeking reactive power cost recovery.

In its recent Generation Interconnection Rule, Order No. 2003, the Commission concluded that an interconnection customer should not be compensated for reactive power when operating within its established power factor range. (Under Order No. 2003, the required power factor range is 0.95 leading [consuming] and 0.95 lagging [supplying], but the transmission provider may establish a different power factor range.) However, the transmission provider must compensate the interconnection customer for reactive power during an emergency. In Order No. 2003-A, the Commission clarified that if a transmission

provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the interconnection customer.

ISOs and RTOs use a variety of methods to compensate generators for reactive power. Most pay generators their allocated revenue requirement or some other form of capacity payment. In addition, some ISOs and RTOs pay a generator for its lost opportunity costs when producing reactive power requires a reduction in real power output. Finally, some ISOs and RTOs impose penalties on generators for failing to provide reactive power, while others don't impose penalties.

International experience. In several countries where the system operator does not own generation facilities, the system operator compensates generators that provide reactive power. These countries include England and Wales, Australia, India, Belgium, the Netherlands and certain provinces of Canada. Sweden follows a different policy. Reactive power in Sweden is supplied by generators on a mandatory basis, and there is no compensation. In the province of Alberta, Canada, generators are penalized for failing to produce or absorb reactive power, and in Argentina, such penalties are imposed not only on generators, but also on transmission operators, distribution operators and large loads. Finally, in Japan, Tokyo Electric Power Co. gives its retail customers a financial incentive to improve their power factors through discounts of the base rate.

Market design issues. As noted above, reactive power can be produced from either static or dynamic sources. Static sources are typically transmission equipment, such as capacitors. Historically, the costs of static sources are included in the revenue requirement of the transmission owner (TO), and, thus, are recovered in the TO's cost-of-service rates from its customers. By contrast, dynamic sources are typically generation equipment, including generators capable of producing both real and reactive power, and synchronous condensers, which produce only reactive power. This generation equipment may be owned either by TOs or independent entities. There are competing views about whether or how such generators should be compensated for reactive power.

Should generators be compensated? One view is that generators should not be compensated for reactive power, at least within specified limits. Under this view, generators should be

required to have a specified minimum capability to produce reactive power as a condition of interconnecting to the grid, and they should bear the costs of maintaining this capability as well as the costs of producing reactive power from this minimum capability.

This paper takes a different view. We conclude that market participants should be compensated for the reactive power that they provide, in order to ensure an adequate, reliable, and efficient supply of reactive power. That is because it is unlikely that an operator will offer to supply reactive power unless it expects to recover its costs and earn a profit. Of course, many generators are able to earn revenue from sources other than reactive power – such as from sales of real power. Thus, much generation investment would continue to be made even if generators are not paid for providing reactive power. However, failing to pay generators for reactive power could reduce the amount of generation investment, because revenue from real power sales and other sources, by themselves, may not be sufficient for some projects to cover the project's costs and return a profit. In addition, paying generators may help retain reactive power capability where it is needed. Failing to pay for reactive power could also reduce the amount of reactive power capability installed in new generation equipment. That is because developers may elect not to add reactive capability beyond the minimum requirements if they are not going to receive any additional revenue from doing so. Also, paying suppliers for reactive power production requested by the system operator will create incentives for the suppliers to follow the system operator's instructions.

Compensating operators for providing reactive power and reactive power capability could also encourage system operators to make good economic decisions within the bounds established by reliability. If suppliers must be paid for reactive power capability, system operators should have a greater incentive to procure reactive power from the lowest cost sources and to avoid procuring excessive reactive power capability in generation pockets where it is not needed.

Comparable compensation for all generators. A related issue is whether all generators should be paid for reactive power. In some control areas that are not operated by ISOs or RTOs, generators owned by the transmission provider are paid for reactive power while other generators are not. We conclude that such discrimination is poor public policy and

could be considered undue discrimination under the Federal Power Act. We think that the Commission's general policy favoring comparability should apply in the reactive power context. That is, independent generators should be eligible for the same compensation for reactive power as a generator owned or affiliated with the transmission provider providing comparable service

However, the level of compensation should depend on the needs of the system. In areas where additional capability and production are needed, prices should be sufficient to encourage additional investment and supply. Conversely, in areas with significant excess capability, lower prices are appropriate so as not to burden customers with excessive costs or to encourage additional investment that is not needed.

Compensation for static versus dynamic reactive power. Another issue is whether owners of static and dynamic sources of reactive power should receive the same compensation. We conclude that the reactive power capability from static sources is less valuable than from dynamic sources, because dynamic sources can adjust their production or consumption of reactive power much more quickly as needed to maintain voltage and prevent a voltage collapse. Thus, reactive power capability from dynamic sources is a different product than the capability from static sources, and the market price for dynamic capability at a given location and time may often be higher than the market price for static capability. However, reactive power that is actually produced or consumed at a given location and time has the same value whether it is provided by a static or dynamic source. Thus, if reactive power is bought and sold in real time, the price faced by all reactive power providers at a given location and time should be the same, regardless of the source. This recommendation is consistent with the pricing policies for real power, where fast-responding units providing operating reserves for real power are paid more than slow-responding operating reserves, while all real power produced at a given location and time is paid the same price.

Pricing options. There are two general ways to compensate generators for providing reactive power. One way is the capacity payment option, in which the generator is paid in advance for the capability of producing or consuming reactive power. The payment could be made through a bilateral contract or through a generally applicable tariff provision. Once the generator is paid, it could be obligated to produce or consume reactive power up

to the limits of its commitment without further compensation when instructed by the system operator. To ensure that the generator follows instructions in real time, the generator could face penalties for failing to produce or consume when instructed. Currently, this is the most common method for compensating reactive power providers.

The other way is the real-time price option, in which the generator is paid in real-time for the reactive power that it actually produces or consumes. Under this option, the generator is paid only for what it produces or consumes, but it pays no penalty for failing to produce when instructed.

It is also possible to combine some of the features of each of these options. For example, a generator might receive a capacity payment in advance in exchange for the obligation to produce or consume reactive power within a specified power factor range upon instruction by the system operator, but might also receive a spot price for producing or consuming additional reactive power beyond the specified range.

Under the capacity payment option, there are at least four methods for determining the capacity payment:

1. **A cost-based payment** – based either on the current (AEP) method, or other cost-based methods.
2. **Capacity market payment.** A generator's installed capacity obligation would include an obligation to provide reactive power within a specified power factor range and the generator's compensation would be bundled in with its capacity payment.
3. **Prices determined through auction.** The ISO or RTO could hold an auction for reactive power capability and the winners of the auction would receive the applicable market clearing price.
4. **Pay nothing** – based on the view that each generator should be obligated to provide reactive power as a condition of interconnecting with the grid.

Under the real-time pricing option, there are at least four methods for determining the spot price:

1. **Pay nothing** – at least for reactive power produced within a specified power factor range. This option may be most appealing when the generator has received a capacity payment in advance for the capability to produce within the specified range.

2. **Unit-specific opportunity costs.** Pay a generator for the unit-specific opportunity cost it incurs due to reduced real power production, either for any reactive power produced or, alternatively, only for reactive power produced outside a specified power factor range underlying any capacity payment that the generator received in advance.

3. **Market clearing prices determined through auction.** Determine real time prices based on a spot market auction for reactive power. In the auction, all accepted bidders at a location could receive the same market-clearing price based on the highest accepted bid. One issue for the auction is whether reactive power prices (i) are calculated directly or (ii) are derived from the implicit opportunity costs associated with real power prices and the supplier's real-power energy bids. Under the direct pricing approach, reactive power sellers would submit price bids for supplying (or consuming) specific amounts of reactive power, and the reactive power price at any location and time would be the highest accepted price bid. Under the derived approach, reactive power suppliers would submit price bids for supplying real power as well as information indicating the trade-off between supplying various amounts of real and reactive power. However, the supplier would not submit a specific price bid for producing reactive power. From the submitted information, the ISO or RTO would calculate the implicit opportunity cost (i.e., the forgone real-power revenue associated with supplying or consuming reactive power) incurred by each supplier. The price for reactive power in the auction would be calculated based on these derived opportunity costs.

4. **Prices (or a pricing formula) announced in advance.** This method is currently used in the United Kingdom and India.

Choosing among the pricing options. Choosing among the options depends on the goals and objectives. We think that a well-designed pricing mechanism can help achieve at least two important goals. The first is to encourage efficient and reliable investment in

infrastructure needed to produce reactive power and maintain the reliability of the transmission system. The second is to encourage efficient production and consumption of reactive power from the existing infrastructure, taking into account the opportunity costs of competing uses of resources, so as to keep rates low.

We have concerns about whether the current methods of procuring and compensating for reactive power promote these goals. For example, current rules treat generators differently from other providers of reactive power. Owners of transmission equipment that provide static reactive power capability receive cost-of-service payments through a routine filing process. However, owners of generators are sometimes expected to provide reactive power capability within established ranges without compensation, as a condition of interconnection to the grid. In addition, the regulatory process often makes it harder for independent generators than for owners of generators that are affiliated with vertically integrated transmission owners to receive compensation for their reactive power capability through routine regulatory filings. Interconnection requirements to provide capability for reactive power provide no compensation in certain locations and this arrangement blunts the incentive to provide this capability. The Commission should review the current AEP methodology of Opinion No. 440 for determining payments for reactive power capability, especially with regard to its effect on investment incentives. Further, the Commission should streamline the process for filing and collecting Opinion No. 440 rates by independent generators. The regulatory process that independent generators must follow in order to receive compensation is much more burdensome and time-consuming than that for affiliated generators. Streamlining the process for independent generators – so as to make the regulatory process the same for affiliated and independent generators – would remedy this problem.

Spot markets for reactive power. Forward contract markets can allow market participants to lock in trades in advance and hedge risk. Developing bid-based reactive power spot markets, operated by ISOs and RTOs, can allow participants to adjust their forward positions as market conditions change, making it less risky to enter into forward contracts. In addition, spot markets can help facilitate meeting demand with the lowest-cost resources that are available in real time. Spot pricing devoid of market power provides signals to improve the efficiency of the system. For example, we have been told of market participants with shunt capacitors that do not dispatch them properly. We suggest price signals can help do the

job. Examples presented in this paper and some preliminary research suggest that a fuller consideration of reactive power in real time spot markets in conjunction with real power markets may have the potential to reduce the total costs of meeting load substantially.

However, the idea of a bid-based reactive power spot market is new and we believe it is too soon to implement one. Simulation and experimentation are needed to understand the effects of alternative auction market designs. In addition, the software and other costs of developing a reactive power auction market should be understood. For the present, while spot auction markets are being further studied, we recommend paying real-time prices for actual reactive power production based on the provider's own opportunity cost or based on administratively determined prices announced in advance, in order to encourage suppliers to produce reactive power where it is needed.

Addressing market power. As noted earlier, many suppliers of reactive power have market power because the number of reactive power suppliers at any location is often very small. Thus, regulatory policies need to be in place to restrict the ability of reactive power suppliers to exercise market power. This paper does not reach a conclusion about how best to the mitigate market power of reactive power providers. Several options should be considered. We mention two options here, but others may also be available. Of course, the traditional method at the Commission for limiting the exercise of market power has been cost-of-service regulation. While the cost-of-service option should be considered, it is not the only available option, and it may not be the best option. Cost-of-service regulation can blunt incentives for suppliers to minimize their costs; cost reductions don't increase profits, but instead reduce the supplier's revenues. Another option is the procedure used in ISO spot markets for real power – that is, to cap the suppliers' bids while allowing all accepted suppliers to receive a market clearing price in the spot market that reflects the highest accepted bid. This option may provide incentives for the supplier to reduce its costs, especially if the supplier does not always set the market clearing price. Cost reductions would not always reduce revenues, and thus, could increase profits.

In the future, however, market power in reactive power markets could be a smaller problem because entry and exit could become easier. With the advent of new technology, equipment that supplies reactive power now comes in smaller increments and can be made mobile

(e.g., truck mounted). These characteristics could allow new suppliers to enter and exit different market locations quickly and for considerably less investment and sunk costs. Current entry rules are a barrier to this technology, however. We need a discussion of how this affects the Commission's policy on market design.

Concluding thoughts. This paper is intended to begin a discussion of regulatory policies affecting reactive power. Any changes in policy resulting from this discussion are likely to take some time to implement, and some changes are likely to be made more easily and quickly than others. For example, policies that promote comparability are likely to be more easily made, and we recommend working to implement them in the near term. These policies include (1) clarifying the requirements and compensation rules for providing reactive power, as well as the definitions underlying these requirements and rules, (2) creating incentives that encourage desired behavior, (3) streamlining the process for compensating independent generators for reactive power capability and provision to make the process comparable to that for affiliated generators, and (4) making reactive power procurement and compensation more transparent, for example by calculating and publishing reactive power production, consumption and prices on a comparable basis to real power. Other policy changes involve more complex issues, and will require more time to consider. Policy changes that involve a complete market redesign will thus need to be implemented over the longer term. The ultimate goal should be an integrated set of co-optimized markets with bilateral markets relatively free from federal regulation. This goal requires research, software development, education and testing, and is likely to require 5 to 10 years to fully implement.

INTRODUCTION
What Is Reactive Power And Why Are We Concerned About It?

What is reactive power? Almost all bulk electric power is generated, transported and consumed in alternating current (AC) networks. Elements of AC systems supply (or produce) and consume (or absorb or lose) two kinds of power: real power and reactive. Real power accomplishes useful work (e.g., runs motors and lights lamps). Reactive power supports the voltages that must be controlled for system reliability.

In an AC electrical system, voltage and current pulsate (described mathematically by sine waves) at the system frequency (in North America this is 60 Hertz, or 60 times per second). Voltage is a measure of the potential energy per electric charge, and current is a measure of the average velocity at which electrons are moving. Voltage (measured in volts) is analogous to pressure in a water or gas system, while current (measured in amperes) is analogous to the velocity of fluid flow – water or gas.

Although AC voltage and current pulsate at the same frequency, they peak at different times. Power is the algebraic product of voltage and current. Over a cycle, power has an average value, called real power, measured in volt-amperes, or watts. There is also a portion of power with zero average value that is called reactive power, measured in volt-amperes reactive, or vars. The total power is called apparent power, measured in volt-amperes, or VA.

Reactive power has zero average value because it pulsates up and down, averaging to zero; reactive power is measured as the maximum of the pulsating power over a cycle. Reactive power can be positive or negative, depending on whether current peaks before or after voltage. By convention, reactive power, like real power, is positive when it is "supplied" and negative when it is "consumed." Consuming reactive power lowers voltage magnitudes, while supplying reactive power increases voltage magnitudes.

An analogy for describing reactive power is a person on a trampoline. While walking across the trampoline, the person will bounce up and down. The bouncing is caused by an exchange of stored energy between the trampoline springs and the Earth's gravitational field. Similarly, reactive power in an electric transmission system is just the pulsating transfer of stored energy

between various kinds of electrical components in the system.

Because voltage and current are pulsating, the power on a transmission line also pulsates. In a transmission system, this pulsating transfer of stored energy results in a loss of power called line losses. In the trampoline analogy, the person's "real" power goes into moving horizontally across the trampoline, while "reactive" power keeps the person standing on the trampoline as it bounces. The effort the person expends to keep standing during bouncing results in no net forward motion, but is necessary to walk across the trampoline. The motion from the trampoline bouncing is always perpendicular to the direction the person is walking; this is called being in quadrature. Similarly, real and reactive power are also in quadrature (90 degrees out of phase) and hence the letter Q is commonly used to designate reactive power. Real power is commonly designated as P.

Reactive power takes up space on transmission lines. Here reactive power is like the head on a beer because it takes up space in the glass leaving less room for the real beer. For a transmission line, the square of the real power plus the square of the reactive power must be less than the square of the thermal capacity (measured in volt-amperes) of the line. When thermal capacity is exceeded significantly for a long time, the line will sag, possibly into vegetation, causing a short circuit, or anneal, resulting in structural damage. Real power losses in transmission lines are proportional to the current in the line. Because power is the algebraic product of voltage and current, the same power at high voltages has a lower current, and hence, has lower losses. Power is transmitted over long distances at a high voltage, up to 765,000 volts, while the power at a wall outlet in the United States is only 110 volts.

Reactive power is difficult to transport. At high loadings, relative losses of reactive power on transmission lines are often significantly greater than relative real power losses. Reactive power consumption or losses can increase significantly with the distance transported. Losses in transmission lead to the expression that reactive power does not travel well. When there is not enough reactive power supplied locally, it must be supplied remotely, causing larger currents and voltage drops along the path.

The main advantage of AC electric power is that the voltage level can be

changed with transformers, which are iron cores wrapped in wire. A current flowing in a wire induces a magnetic field around the wire; a time-varying current induces a changing magnetic field. If a coil of wire is placed in a changing magnetic field, a voltage is induced in the coil. The changing current in a coil will also induce voltages in other coils in the magnetic field. This is how transformers change the voltage level of AC power. The number of wires on each side of the transformer core determines the voltage level at that side.

The Need for Reactive Power. Voltage control (keeping voltage within defined limits) in an electric power system is important for proper operation of electric power equipment to prevent damage such as overheating of generators and motors, to reduce transmission losses and to maintain the ability of the system to withstand disturbances and prevent voltage collapse. In general terms, decreasing reactive power causes voltages to fall, while increasing reactive power causes voltages to rise. A voltage collapse occurs when the system is trying to serve much more load than the voltage can support.

Inadequate reactive power supply lowers voltage; as voltage drops, current must increase to maintain the power supplied, causing the lines to consume more reactive power and the voltage to drop further. If current increases too much, transmission lines trip, or go off-line, overloading other lines and potentially causing cascading failures. If voltage drops too low, some generators will automatically disconnect to protect themselves. Voltage collapse occurs when an increase in load or loss of generation or transmission facilities causes dropping voltage, which causes a further reduction in reactive power from capacitors and line charging, and still further voltage reductions. If the declines continue, these voltage reductions cause additional elements to trip, leading to further reduction in voltage and loss of load. The result is a progressive and uncontrollable decline in voltage, all because the power system is unable to provide the reactive power required to supply the reactive power demand.

Reactive power needs are a critical part of the planning process. Supply-chain management, the name often given to the manufacturing-transportation-storage-consumption process, is usually measured in days,

weeks or months for most industries. For electricity this process takes less than a second – the ultimate just-in-time system. If there is a disruption in the system, corrective action is called for in seconds or minutes. As a result, the system must be planned so that it can respond to contingencies. Auctions can be employed to satisfy the procurement needs of the planning process.

Reactive power needs are determined in the planning process, which is part engineering, part economics and part judgment. The engineering analysis requires running large, complex mathematical computer models of the electric system. The economic analysis requires putting costs or bids into the models to determine how to achieve an efficient, reliable system. The judgment arises due to the large number of modeling choices, expert assumptions and approximations that often are necessary.

Reactive Power and Blackouts. Inadequate reactive power leading to voltage collapse has been a causal factor in major power outages worldwide. Voltage collapse occurred in the United States in the blackouts of July 2, 1996, and August 10, 1996, on the West Coast. Voltage collapse also factored in the blackouts of December 19, 1978, in France; July 23, 1987, in Tokyo; March 13, 1989, in Québec; August 28, 2003, in London; September 23, 2003, in Sweden and Denmark; and September 28, 2003, in Italy.

While the August 14, 2003, blackout in the United States and Canada was not due to a voltage collapse as that term has been traditionally used by power system engineers, the Task Force Final Report said that "insufficient reactive power was an issue in the blackout."[1] The report also cites "overestimation of dynamic reactive output of system generators"[2] as a common factor among major outages in the United States. Due to difficulties modeling dynamic generator output, the amount of dynamic reactive output from generators has been less than expected, worsening voltage problems and resultant power outages. Recommendation 23 of the blackout report, "Strengthen reactive power and voltage control practices in all NERC regions," states: "The task force also recommends that FERC and appropriate authorities in Canada require all tariffs or contracts for the sale of generation to include provisions specifying that the generators can be called upon to provide or increase reactive power output if needed for reliability purposes, and that the generators will be paid for any lost sales

[1] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and* Recommendations, April 2004, 18.

[2] Outage Task Force *Final Report*, 107.

attributable to a required increase in the production of reactive power."

Many devices contribute to a system's reactive power and voltage profile. Generators can supply and consume reactive power. For a fixed amount of energy input, the generator can, by changing control settings, supply real and reactive power subject to the conservation of energy and the equipment capability. Capacitors, also called condensers, supply reactive power. A transmission line, due to its physical characteristics, supplies reactive power under light loading and consumes it under heavy loading. Power system voltages are controlled through the supply and consumption of reactive power. Devices called relays sense overloads and send a signal to a circuit breaker to remove the asset from the network.

Market Design for Reactive Power. For almost a century, electricity policy and practice were geared to the vertically integrated utility. Tradeoffs between generation and transmission investments were largely internal company decisions and, for the most part, out of the public view. Reactive power investment costs were included in rate base and redispatch costs were placed in fuel adjustments clauses and recovered from customers. While the Public Utility Regulatory Policies Act of 1978 (PURPA) required utilities to buy power from qualifying third-party generators, PURPA did not specifically address the purchase of reactive power. With the introduction of independent power producers (IPPs) and merchant transmission, we need to reexamine the role of who supplies and consumes reactive power and who is responsible to pay and be paid for reactive power.

When the industry consisted of mostly vertically integrated utilities, the planning process was often shrouded in engineering, mathematics and modeling jargon, making it difficult for many to understand. Reactive power requirements were opaque. With the advent of independent system operators (ISOs) and regional transmission organizations (RTOs), the process has become less opaque.

Unlike the cost of real power, for generators, most of the costs of reactive power are sunk investment costs. Therefore, decisions made today will affect the industry for years to come. Some argue that providing reactive power for free is good citizenship or good utility practice. In the era of the vertically

integrated utility, good citizenship was accompanied by cost recovery. Now, IPPs have no rate base or fuel adjustments clauses, but the costs are still incurred. In some ISOs, IPPs are paid a demand charge for certain reactive power capability and lost-opportunity costs if they need to reduce real power output. Proper real time price signals and capability payments would provide incentives to enhance both reliability and the efficiency in the short term.

Efficient competition is a way to achieve efficiency and reduce costs to consumers. Efficient competition is difficult to achieve, but competition merely for the sake of competition is just sport. Due to innovation and technological progress, the optimal industry structure and mode of regulation may need to change. As regulated markets move from franchised monopolies toward competition, regulation needs to move from direct price regulation to market rules. Competitive markets require a competitive market design. In some markets, little more than basic contract and property rights laws and their enforcement are necessary. In electricity markets, the value to society of continuous high-quality electric power makes additional market rules necessary. As Nobel Prize winning economist Ronald Coase stated:

> "All exchanges regulate in great detail the activities of those who trade in these markets … these exchanges are often used by economists as examples of a perfect competition … It suggests … that for anything approaching perfect competition to exist, an intricate system of rules and regulations would be normally needed. Economists observing the regulations of the exchange often assume that they represent an attempt to exercise monopoly power and to aim to restrain competition. … An alternative explanation for these regulations: that they exist in order to reduce transaction costs … Those operating in these markets have to depend, therefore, on the legal system of the State."[3]

[3] R.H. Coase, *The Firm, the Market and the Law*, Chicago (University of Chicago Press, 1988), 1-31.

Put differently, efficient market design does not just happen spontaneously. It is the result of a process that includes full discussion, learning and informed judgments by all affected and responsible parties.

Many argue that both transmission and reactive power are public goods. This is an oversimplification. When a transmission line is congested, the line

no longer has a public good characterization. The electric system is replete with externalities and assets that are both substitutes and complements, which can change based on system conditions. Some argue that scale economies limit the ability of competition to achieve efficiency, but redundancy required by reliability contingency considerations limit the use of possible scale economies. Reactive power supply or consumption can incur opportunity costs when generators must reduce real power output to supply reactive power. Reactive power is consumed by transmission lines when highly loaded.

To function efficiently, markets should be complete. That is, for all scarce services, compensation must be received by the suppliers and be paid for by the consumers. Otherwise, supply and investment signals are muted, shortages can develop and curtailments become necessary. This holds true for reactive power. Sellers should be paid a market price or rate for reactive power that they supply so as to avoid shortages. Buyers should pay the market price or rate. Due to the system design, customers often cannot be disconnected from the system in time to avoid a blackout. Therefore, the capability to serve them may need to be purchased in advance. Complete pricing may include both commodity and capacity markets due to lumpiness in investments, system contingencies and lack of demand response.

Without complete pricing, market participants must mark up the remaining priced products in hopes of compensation for the loss of complete pricing. This does not always result in efficient decisions. Further, because correct incentives do not exist, the system operator (SO) may need to resort to command and control to obtain necessary nonpriced resources. Investment decisions may be distorted and market monitoring problems may arise.

Reactive power – supplied and consumed by generation, load and transmission – is ubiquitous in AC electric systems. The supply and demand of reactive power is the dominant controller of voltage in many locations. Reactive power capability requires both fixed and sunk cost investment. Reactive power supply has cost tradeoffs. Like real power reserves, reactive power reserves have different qualities. Some of these differences include speed and continuity of response and response capability when voltage is decreasing.

Like real power, a portfolio of reactive power sources may be optimal. The highest valued reactive power comes from generators that have almost instantaneous response that is not a direct function of a voltage. Reactive power from capacitors has a slow response and declines with the square of the voltage.

Competition in generation makes it important to consider the development of complementary markets for reactive power. Some argue that reactive power is cheap. Economic analysis of reactive power is often dismissed using phrases reminiscent of the 1950s claim for nuclear power as "too cheap to meter,"[4] yet reactive power is not costless and is critical to system reliability. Sufficient reactive power is critical to avoiding an extremely costly system collapse, but the cost of avoiding a blackout is difficult to calculate. The transfer characteristics of reactive power makes the topology for reactive power markets small relative to real power markets, raising market power concerns, but market entry by many devices that can supply and consume reactive power increase the potential number of market participants.

The remainder of the paper reviews the physical characteristics of the devices and costs of supplying reactive power; reviews the history of reactive power pricing at the Commission and internationally; provides an economic analysis of reactive power pricing and pricing options for reactive power; and provides conclusions, recommendations and questions for the Commission's future approach to reactive power markets. Several appendices are included to examine in technical detail the literature, investment incentives, market design and options discussed in the main body of the paper.

Physical Characteristics and Costs of Reactive Power in AC Systems

Reactive power is an inherent part of the generation, transmission and distribution of electricity. Inductance and capacitance are inherent properties of the electric power system elements such as transmission lines, transformers and capacitors. Inductance consumes reactive power and capacitance supplies reactive power. Most of the electric power loads are inductive in nature. Induction motors and transformers consume reactive power. Common examples of applications of induction motors include air conditioners, household appliances, mining, industrial equipment and manufacturing processes. Underground and overhead transmission lines have inductance and capacitance, and can either supply reactive power or consume reactive power depending on the line loading. Generators can supply or consume reactive power within limits.

Reactive power needs to be managed or compensated in a way to ensure sufficient amounts are being produced to meet demand and so that the electric power system can run efficiently. Significant problems (e.g., abnormal voltages and system instability) can occur if reactive power is not properly managed. Capacitors, which supply reactive power, can be switched into a system in real-time to compensate for the reactive power consumed by the electric power system during periods of heavy loading. Similarly, inductors, which consume reactive power, are added to compensate for the reactive power supplied by the electric power system during periods of light loading. These devices are installed throughout the electric power system to maintain an acceptable voltage profile for a secure and efficient power system operation. Generators can also provide or absorb reactive power. Reactive power compensation can be either static (e.g. capacitors or inductors) or dynamic (e.g. generators) in nature.

Physical Characteristics. Reactive power compensation can be well managed under predictable changes in load demands and generation balances, scheduled generation and transmission outages and contingencies that are within the operating criteria. A key characteristic of reactive power demand is the magnitude and speed at which it changes over time. Due to the varying nature of loads, reactive power requirements, both supplying and consuming, can change significantly (and sometimes unpredictably) during the day at the same location.

Generally, reactive power support is divided into two categories: static and dynamic. Capacitors and inductors (or reactors) supply and consume static reactive power, respectively. These are called static devices since they have no active control of the reactive power output in response to the system voltage. Synchronous generators, synchronous condensers, Flexible AC Transmission Systems (FACTS) including static var compensators (SVC), static compensators (STATCOM), and Dynamic Var (D-var) are considered as dynamic reactive power devices capable of changing their output according to pre-set limits in response to the changing system voltages.

Synchronous Generators. Most generators connected to the electricity grid are synchronous generators, meaning that they operate synchronously at the same electrical frequency. Generator settings can be adjusted to produce combinations of real power and reactive power. When the generator increases its reactive power output, its real power capability may need to be reduced if the generator reaches its limits; a discussion of generator capability limits appears at the end of this chapter. Reactive power supply from generators requires a minimal additional amount of fuel or real power from the network. The cost of a generator depends on the capacity, fuel type and voltage level. The reactive power capacity for a generator is determined by thermal limits. Thermal limits are determined by the thermal properties of the materials in the generator; if the generator overheats, insulation will degrade and its parts may be damaged. Because the reactive power constraints in generators are thermal and equipment takes some time to heat to the point of degradation, generators are designed to provide significantly increased amounts of reactive power output for short periods.

A generator can increase or decrease reactive power output smoothly and almost instantaneously within its designed capabilities. Generators have a longer response time if the real power output needs to be adjusted or the generator is offline; the generator ramp rate and startup time will determine how quickly the generator can adjust its reactive power output in these situations. Generators have high maintenance costs due to their moving mechanical parts and cooling systems. There are about 10,000 synchronous generators in North America with a combined maximum reactive power capacity of 600,000 Mvar[5] and maximum real power capacity of approximately 900,000 MW (but due to generator constraints discussed

[5] Data from PowerWorld software, compiled from NERC and FERC filings.

later in this chapter, these maximum capacities are not simultaneously available).[6]

Figure 1: **Synchronous Generator Leaving the Factory**

Source: Photo Courtesy of Hitachi

Distributed Generation. Distributed generators are small power sources including microturbines, fuel cells and engine generators connected to lower-voltage electric distribution systems. They may be owned by utilities or by customers, and are often owned by large industrial plants. Distributed generators have the same reactive power characteristics as large generators – they produce dynamic reactive power and the amount of reactive power does not necessarily decrease when voltage decreases. The reactive power output can be quickly adjusted within the generator operating limits, but will require more time if the generator needs to be started or its real power output needs to be adjusted. The major advantage of distributed generators is that they provide reactive power capability locally, often at the site of large loads, reducing reactive power losses in transmission lines.[7]

[6] Energy Information Administration (EIA), *Electric Power Annual* (2003), Chapter 2, Table 2.1, Existing Net Summer Capacity by Energy Source and Producer Type, 1991 through 2002, at **http://www.eia.doe.gov/cneaf/electricity/epa/epat2p1.html**

[7] J.D. Kueck, B.J. Kirby, L.M. Tolbert and D.T. Rizy, "Tapping Distributed Energy Resources," *Public Utilities Fortnightly*, September 2004, 46-51.

Wind Generators. Wind is naturally intermittent and therefore must be approached by planners and system operators differently than conventional thermal and hydroelectric generation. The variable and largely uncontrollable nature of wind generation introduces new challenges into the control of the power system. Integration of a continually fluctuating, uncontrolled generation resource such as wind impacts the control systems in all time frames. Consequently, the operational and scheduling systems must adjust generating patterns to accommodate the variability in the wind in order to maintain the same level of system reliability. These adjustments are necessary to ensure that sufficient generation is available to meet the control area load and interchange schedules on the various control time frames.

In addition, some wind facilities – especially older facilities – can have asynchronous (induction) generator designs that do not supply reactive power, but may actually draw reactive power from the system. However, newer models can provide reactive power and are designed with a selectable power factor ranging from 0.90 lagging to 0.95 leading. For these new generators, the power factor is settable at each Wind Turbine Generator (WTG) or by the plant SCADA system for the whole farm. Dynamic var control, commonly called Dvar, can be supplied to control the wind plant's power factor, or voltage. Dvar systems can optimize local system conditions to improve plant reliability and availability. Dvar can be customized to meet the local utility demands. Equipment with Dvar capabilities is more expensive but has better var control capabilities. Many WTGs currently operating or in storage ready for sale do not have this capability. However, for large wind farms located away from load on a weak grid, the Dvar capabilities will most probably be required to meet reliability and stability requirements.

Synchronous Condensers. Synchronous condensers are synchronous machines that are specially built to supply only reactive power. Synchronous generators that are not economic to operate can be modified into synchronous condenser operation. The conversion costs are typically in the $2 million to $3 million range. Synchronous condensers consume approximately 3% of the machine power rating in real power from the network. Synchronous condensers have similar response times and high maintenance costs of generators. In North

America, most synchronous condensers connected to the transmission system are retired fossil or nuclear power plant AC machines that have been converted. Some hydro generators can operate as synchronous condensers.

Supervar. Supervar machines are rotating machines, much like motors and generators, that use high temperature superconductor technology. They serve as reactive power "shock absorbers" for the grid, dynamically generating or absorbing reactive power, depending on the voltage level of the transmission system. Supervar machines use standard synchronous condenser frames and stator coils mated with new, power-dense rotor coils made from High Temperature Superconducting (HTS) wire. The result is a synchronous condenser that is more efficient than conventional machines - without the typically high rotor maintenance costs. Supervar machines are specifically designed for continuous, steady-state dynamic var support while having multiples of their rated output in reserve for transient problems. The HTS rotor enables these machines to provide up to eight times their rated capacity for short periods. Supervar machines can also serve as lower cost replacements for old, polluting inner city reliability-must-run (RMR) generating facilities that are required to operate in order to maintain system reliability and voltage support. There is one prototype Supervar installation in the US.[8]

[8] American Superconductor, www.amsuper.com.

Transformers. Generators and synchronous condensers operate at voltages lower than transmission system voltages and are connected to high voltage transmission lines through generator step-up transformers. Transformers are electromagnetic devices that convert power from one voltage level to another; they are inductive devices and therefore consume reactive power. Transformers are also used throughout the power network to change voltage from high transmission levels to lower distribution levels.

Transformer Taps. Large power transformers are generally equipped with "voltage tap changers," sometimes called "taps," with tap settings to control the voltages either on the primary or secondary sides of the transformer by changing the amount and direction of reactive power flow through the transformers. Tap changers do not consume or supply reactive power; taps force voltage on one side of the transformer up, at the expense of lowering the voltage on the other side. Taps can be thought of as pumping reactive

power from one side of the transformer to the other to regulate voltage. Transformer taps can be controlled automatically based on local system conditions, or manually. The insulators and contacts used in tap changers are subject to high currents and deteriorate over time; they must be replaced about every 15 years. On-load tap changers can change the tap position while the transformer is energized. Tap changers generally have 32 steps and each step can move within several seconds, depending on the design and system requirements. Adding a tap changer to a transformer when it is initially designed and built is a relatively small cost in comparison to the cost of the transformer. The North American electric power system has about 8,000 tap-changing transformers, and 15,000 fixed tap transformers.[9]

### Figure 2: **Transformer**

Source: Photo courtesy of Siemens

Phase Shifting Transformers. Phase Shifting Transformers (PSTs), also called Phase Angle Regulators (PARs), allow system operators to control real power flow. Phase shifting transformers have taps that control the phase angle difference across the transformer. Increasing the phase angle difference across a transformer has the effect of increasing the impedance of the line, which will reduce the amount of real power on the line (power flows distribute among lines according to the relative impedances of the lines). Phase shifting transformers are usually installed to control real power flow, especially along parallel paths. Phase shifting transformers are also a useful tool for reactive power control. Controlling the real power flow along a line allows for control of the reactive power consumed or produced by the line. Costs of phase shifting transformers are similar to costs of regular transformers.

Transmission Lines. Electric transmission lines have both capacitive and inductive properties. The line capacitance supplies reactive power and the line inductance consumes reactive power. At a loading known as surge impedance loading (SIL), the reactive power supplied by the line capacitance equals the reactive power consumed by the line inductance, meaning that the line provides exactly the amount of Mvar needed to support its voltage. Lines loaded above SIL consume reactive power, while lines loaded below SIL supply reactive power. The amount of reactive power consumed by a line is related to the current flowing on the line or the voltage drop along the line; the amount of reactive power supplied by a line is related to the line voltage. An ideal line with zero resistance (zero real power losses) that is loaded at its surge impedance loading will have the same voltage at both ends because it is not supplying or consuming reactive power. Figure 3 shows that the consumption of reactive power by transmission lines increases with the square of current. Thus, when it is critically needed during large power transfers, reactive power is the most difficult to transport. When reactive losses are negative, the line is supplying reactive power; when they are positive, it is consuming reactive power.

Figure 3: **Transmission Line Real and Reactive Power Losses vs. Line Loading**
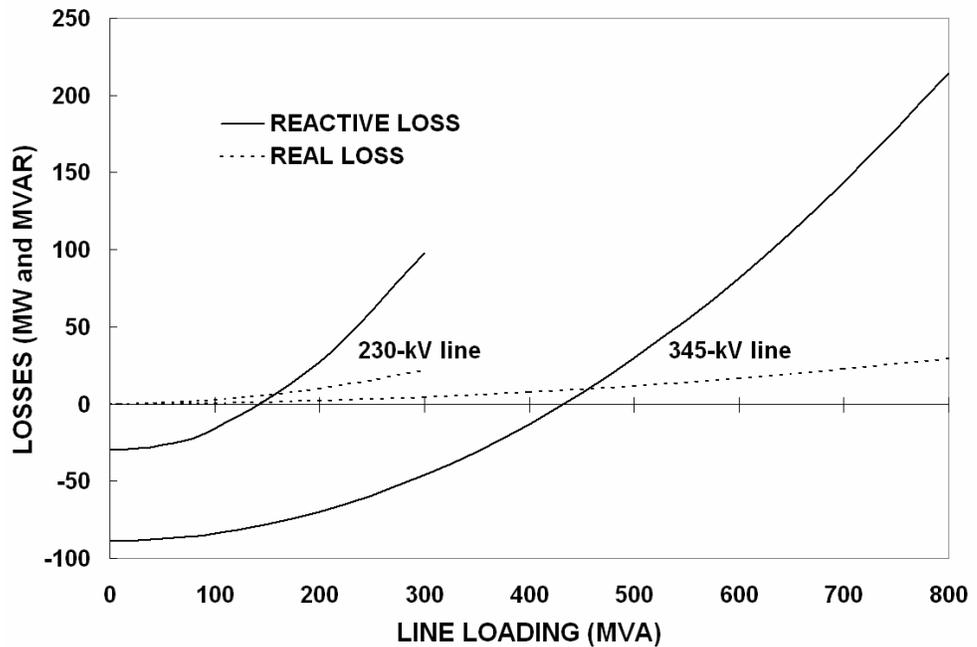
Source: B. Kirby and E. Hirst 1997, *Ancillary-Service Details: Voltage Control*, ORNL/CON-453, Oak Ridge National Laboratory, Oak Ridge, Tenn., December 1997.

High voltage DC transmission lines. High voltage DC transmission lines (HVDC) transmit power via DC (direct current). They normally consist of two converter terminals connected by a DC transmission line and in some applications, multi-terminal HVDC with interconnected DC transmission lines. The converter terminals consist of electronic converters, converter transformers, filters and capacitors to convert power from AC to DC and from DC to AC. In addition to voltage conversion, the converters are capable of controlling the amount of power flows and direction over the DC transmission line.

Because DC transmission lines are transmitting power at zero hertz, the reactive power consumption on the line is zero. The converters require reactive power for the conversion process typically in the range of 40% of the power rating of each of the converter terminals. Therefore, for a 1,000-

MW HVDC transmission, 400 Mvar is typically required at each terminal. The reactive power is required to compensate for the reactive power consumption in the converter transformers and to maintain an acceptable AC voltage level on the AC side of the converter terminals. Much of this reactive power requirement is provided by shunt capacitors and filters, which are required to filter out or reduce the harmonic currents resulting from AC waveform chopping in the AC-DC and DC-AC conversion processes. Therefore, a properly designed HVDC system is essentially self-sufficient in reactive power. Due to its inherently fast electronic control, it is also capable of supporting the AC terminal voltages by controlling the DC power flow over the line and consequently the reactive power consumption in the converter transformers.

Traditional HVDC and transmission is installed for special applications such as long distance power transmission (e.g., hydro or coal-by-wire) and submarine power transmission. Back-to-Back DC and HVDC Light are specific types of HVDC systems. HVDC Light uses new cable and converter technologies and is economical at lower power levels than traditional HVDC.[10] Back-to-Back DC is used for asynchronous connection of two AC systems with different system characteristics that cannot be connected via AC ties (Eastern United States to Québec, Eastern United States to Western United States and Eastern and Western United States to the ERCOT part of Texas are examples).

Switched Shunt Capacitors. During heavy load periods, switched shunt capacitors are utilized to provide voltage support by injecting reactive power to the power system. Switched shunt capacitors are connected to the system through mechanical switches or circuit breakers and their real power losses are very small. Reactive power output from capacitors is proportional to the square of the voltage. This can be a problem during a contingency or a depressed voltage condition; as the voltage falls, the reactive power supplied by the capacitors decreases according to the square of the voltage, causing voltage to fall further.

Capacitor banks are sets of capacitors that are installed in a substation. The capacitors in a bank are switched in blocks. Switched capacitors cannot smoothly adjust their reactive power output because they rely on mechanical

[10] www.abb.com.

[11] Cost data from EIA, "Upgrading Transmission Capacity for Wholesale Trade," March 2002, at http://www.eia.doe.gov/cneaf/pubs_html/feat_trans_capacity/w_sale.html.

[12] Data from PowerWorld software, compiled from NERC and FERC filings.

switches and take several cycles (less than one second) to operate. When capacitors are switched out, they must be discharged before reconnection, normally with discharge time ranging from two to fifteen minutes. In special applications requiring switching-out and fast reconnection, the capacitor banks are equipped with fast discharge reactors that will discharge the capacitors in about 120 milliseconds (ms), thus enabling them to be reconnected to provide voltage support to the power system. Capacitor banks range from $1 million for 50 Mvar at 115 kV to $5 million for 200 Mvar at 500 kV; adding additional capacitors costs $500,000 or more, depending on the voltage and the Mvar added.[11] Capacitor banks and switches have relatively low maintenance costs. There are approximately 5,000 switched shunt capacitors in the North American power system, with about 170,000 Mvar of capacity.[12]

Series Capacitors. Series compensation is based on controlled insertion and removal of series capacitors in AC transmission lines. Series capacitors provide reactive power to the power system according to the square of the line current – the higher the line current, the more reactive power support. Due to characteristics of the impedance of a series capacitor compared to that of the line impedance, a series compensated transmission line is electrically reduced to a shorter distance, thereby increasing its transfer capability. In some situations, series capacitors can excite low-frequency oscillations, which can damage turbine-generator shafts. Series capacitors have similar costs to shunt capacitors, and are used on long transmission lines, especially in the western United States.

Flexible AC Transmission Systems (FACTS). FACTS are technologies that increase flexibility of transmission systems by allowing control of power flows and increasing stability limits of transmission lines. FACTS devices can be installed in a substation, requiring less space and permitting than additional transmission lines. There are several varieties of FACTS devices. Some of the FACTS devices for reactive power management are static var compensators (SVC), static synchronous compensators (STATCOM), dynamic var (D-var) and distributed superconducting magnetic energy storage (D-SMES).

Static Var Compensators. Static var compensators (SVCs) are basically

shunt capacitors or shunt reactors connected to the system via power electronic switches called thyristors to control the voltage by supplying or consuming system reactive power. Similar to capacitors, the reactive output of an SVC varies according to the square of the connected bus voltage.

Static Compensator. A Static Compensator (STATCOM) provides voltage support and control to the system similar to a synchronous condenser, without the spinning inertia, and therefore is superior to SVCs or capacitors in mitigating voltage instability leading to system collapse. It is basically a Voltage Source Converter (VSC), using power electronic switches called IGBTs (insulated gate bipolar transistors) to convert a DC voltage input into a 3-phase voltage at 60 hertz with the additional capabilities of fast control of the phase angle and amplitude. Therefore, reactive output from a STATCOM is independent of system voltage.

Both SVCs and STATCOMs are controlled by microprocessors that automatically regulate bus voltages within a defined band. SVCs are usually large installations in substations and STATCOMs take up slightly less space in the substation. Once installed, they do not require fuel inputs but do use a small amount of electricity from the network. In the 115-230 kV range, SVCs typically operate in ranges of 0-100 Mvar inductive and 100-200 Mvar capacitive, and cost $5 million to $10 million. At higher voltages, SVCs range from 300 Mvar inductive to 500 Mvar capacitive, and cost $10 million to $15 million.[13] Smaller SVCs can change output in a few milliseconds. Larger SVCs can make small changes quickly, but may take a few seconds to make larger changes. Output from SVCs can be varied continuously – they do not require the discharge time needed for switched capacitor banks. There are more than 30 SVCs installed in the United States, ranging from 30 Mvar to 650 Mvar each.[14]

STATCOMs are more compact than SVCs, requiring less space in a substation. SVC and STATCOM maintenance costs are higher than capacitor banks, but much less than generators. STATCOMs are installed at seven sites in the United States, ranging between 30 Mvar and 100 Mvar each.

[13] Cost estimates provided by ABB, e-mail from Eric John, employee of ABB, to FERC's Mary Cain, dated July 20, 2004.

[14] ABB SVC projects worldwide, available at **www.abb.com**.

Figure 4: **Installation of Mobile SVC**

Source: Photo Courtesy of Areva Transmission and Distribution

Relocatable SVCs consist of modules that can be transported with normal transportation equipment (truck, train, boat). They take up to a few weeks to install, depending on the location. They need concrete platforms and some of the modules need to be bolted into the concrete. Moving the modules

from the transportation vehicle to the cement platform is done with a crane or similar equipment. The modules have prefabricated cables and buswork for easy interconnection. Currently, relocatable SVCs are being used in Japan, Switzerland, Australia and the United Kingdom.

D-var (Dynamic Var). D-var voltage regulation systems dynamically regulate voltage levels on power transmission grids and in industrial facilities; D-var is a type of STATCOM. D-var dynamic voltage regulation systems detect and instantaneously compensate for voltage disturbances by injecting leading or lagging reactive power to the part of the grid to which the D-var is connected. The amount of reactive power delivered per unit varies typically from 1 Mvar to 8 Mvar continuous, with near instantaneous reactive power output up to 24 Mvar per unit. There are currently 22 installations of D-var systems in North America.[15]

D-var voltage regulation systems are scalable and mobile, characteristics that allow utilities to install them in their power grid at locations that need the greatest amount of reactive power support. D-var dynamic voltage regulation system components can be configured inside a standard truck trailer that can be moved to substations for optimized var support throughout a power grid or placed in a standard enclosure for more permanent siting at a substation. D-var systems provide dynamic var support for transmission grids that experience voltage sags, which are typically caused by high concentrations of inductive loads, usually in industrial manufacturing centers, or from weaker portions of the transmission grid, typically in remote areas or at the end of radial transmission lines.

D-var systems also are suited to address the need for dynamic var support at wind farms. Because of the remote locations of most large wind farms, the power they generate must often be delivered a long distance to the ultimate customer on a relatively weak utility transmission grid. A D-var system is ideally suited to mitigating voltage irregularities at the point of interconnection between the wind farm and the grid. D-var systems can be integrated with low cost capacitor banks to provide an extremely cost-effective solution for large wind farms. For instance, a small (8 MVA) D-var device combined with a number of medium voltage capacitor banks is sufficient to solve most of the voltage problems associated with wind farms.

[15] American Superconductor, www.amsuper.com.

Distributed SMES, or D-SMES. A superconducting magnetic energy storage (SMES) system is a device for storing and instantaneously discharging large quantities of power. These systems have been in use for several years to solve voltage stability and power quality problems for large industrial customers. A distributed-SMES (D-SMES) system is a new application of proven SMES technology that enables utilities to improve system reliability and transfer capacity.

D-SMES is a shunt-connected Flexible AC Transmission (FACTS) device designed to increase grid stability, improve power transfer and increase reliability. Unlike other FACTS devices, D-SMES injects real power as well as dynamic reactive power to more quickly compensate for disturbances on the utility grid. Fast response time prevents motor stalling, the principal cause of voltage collapse. D-SMES devices can be transported on standard truck trailers, with one 250-kW system per trailer. The inverters provide up to 2.3 times nominal instantaneous over-current capability and can also be configured for continuous var support. Each 250-kW trailer operates independently, improving reliability. Six D-SMES systems are installed in the midwest United States.[16]

[16] American Superconductor, www.amsuper.com.

Costs. Differences in effectiveness and costs of the different devices dictate that reactive power generally is provided by a mix of static and dynamic devices. The cost of reactive power service depends upon the choice of equipment. The costs of satisfying static reactive power demands are much lower than those of satisfying dynamic reactive power demands. While capital costs tend to dominate, the costs of providing reactive power also include generator fuel costs, operating expenses and the opportunity costs from not generating real power. The capital costs of static sources of reactive power, such as capacitors, are orders of magnitude lower than the capital costs of dynamic sources, such as generators, SVCs and synchronous condensers. Table 1 shows the speed, voltage support and costs for the different sources of reactive powers and does not include transformer tap changers. The ability to support voltage means the ability to produce reactive power when voltage is falling. The availability of voltage support indicates how quickly a device can change its reactive power supply or consumption. Disruption is low for devices that can smoothly change reactive power output and high for devices that cannot change reactive power output smoothly.

Table 1: **Characteristics of Voltage-Control Equipment**

Equipment type	Speed of response	Voltage Support			Costs		
		Ability	Availability	Disruption	Capital (per kvar)	Operating	Opportunity
Generator	Fast	Excellent, additional short-term capacity	Low	Low	Difficult to separate	High	Yes
Synchronous Condenser	Fast	Excellent, additional short-term capacity	Low	Low	$30-35	High	No
Capacitor	Slow	Poor, drops with V^2	High	High	$8-10	Very low	No
Static Var Compensator	Fast	Poor, drops with V^2	High	Low	$45-50	Moderate	No
STATCOM	Fast	Fair, drops with V	High	Low	$50-55	Moderate	No
Distributed Generation	Fast	Fair, drops with V	Low	Low	Difficult to separate	High	Yes

Source: Modified from B. Kirby and E. Hirst, *Ancillary-Service Details: Voltage Control,* ORNL/CON-453, Oak Ridge National Laboratory, Oak Ridge, Tenn., December 1977.

Generator Reactive Power Capability. An electricity generator has two parts. The armature, also known as the stator, is the stationary part of the generator. It is a large cylinder, with slots running lengthwise on the inside. Coils of wire go through the slots. The field, also known as the rotor, is an electromagnet that rotates inside the stator.

Figure 5 shows a generator stator with a rotor inside (the rotor is sticking out farther than usual for illustrative purposes). In fast generators, the rotor is made of solid steel; slots are cut into its surface and coils of wire are wound through the slots. The generator shaft is a rod through the center of the rotor, and this is connected to the prime mover, which can be a steam, combustion, wind or hydroelectric turbine. When the turbine spins, the generator rotor spins, and the spinning magnet of the rotor induces an electric field in the stator wires. The stator is connected to electrical equipment that transfers electrical power from the generator to the power system. The stator and rotor are enclosed, and air or compressed hydrogen cools the generator inside the enclosure; some generators have water pipes installed on the stator for additional cooling.

Figure 5: **Generator Stator and Rotor**
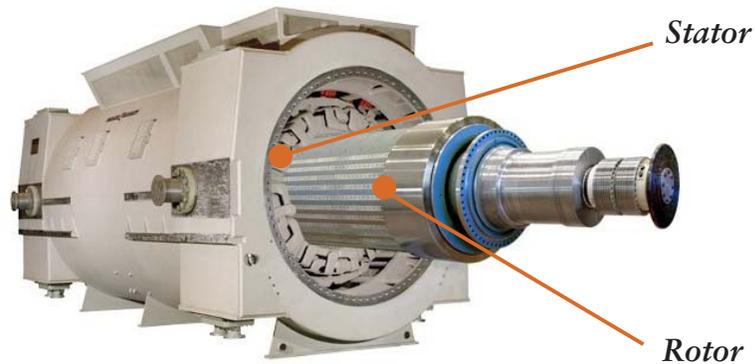
Source: Photo courtesy of General Electric Co.

A generator's output capabilities depend on the thermal limits of various parts of the generator and on system stability limits. Thermal limits are physical limits of materials such as copper, iron and insulation; if the generator overheats, insulation begins to degrade and over time this could result in equipment damage. Increasing real power output of a generator heats up the armature. Increasing reactive power output heats up the field windings and the armature. To supply reactive power, the generator must increase the magnetic field to raise the voltage it is supplying to the power system; this means increasing the current in the field windings, which is limited by the thermal properties of the metal and insulation. The field current is supplied by the generator exciter, which is a DC power supply connected to the generator. The field current can be quickly adjusted by automatic control or with a dial to change the reactive power supplied or consumed by the generator. Stability limits are determined by the ability of the power system to accept delivery of power from the connected generator under a defined set of system conditions including recognized contingencies. All generators connected to a power system operate at the same electrical frequency; if a generator loses synchronism with the rest of the system, it will trip offline to protect itself.

Current and voltage are both time-varying quantities in sinusoid waveform; when current lags voltage, it reaches its peak after the voltage, and when current leads voltage, it peaks before the voltage.

Figure 6 shows current and voltage waveforms. The blue squares represent a voltage waveform. The red solid line is current in phase with the voltage. The green dotted line is current leading voltage by 45 degrees, and the purple dashed line is current lagging voltage by 45 degrees. Phase angle is a quantity that indicates the difference in time of peaks of sinusoid waveforms; the phase angle difference between the blue and green waveforms is 45 degrees. Power factor is a measure of real power in relation to reactive power; mathematically, it is defined as the cosine of the phase angle between voltage and current. When the power factor is leading, the current phase angle is greater than the voltage phase angle; when the power factor is lagging, the current phase angle is smaller than the voltage phase angle. Capacitors supply reactive power and have leading power factors, while inductors consume reactive power and have lagging power factors. The convention for generators is the reverse. When the generator is supplying reactive power, it has a lagging power factor and its mode of operation is referred to as overexcited. When a generator consumes reactive power, it has a leading power factor region and is underexcited.

Figure 6: **Voltage and current waveforms**
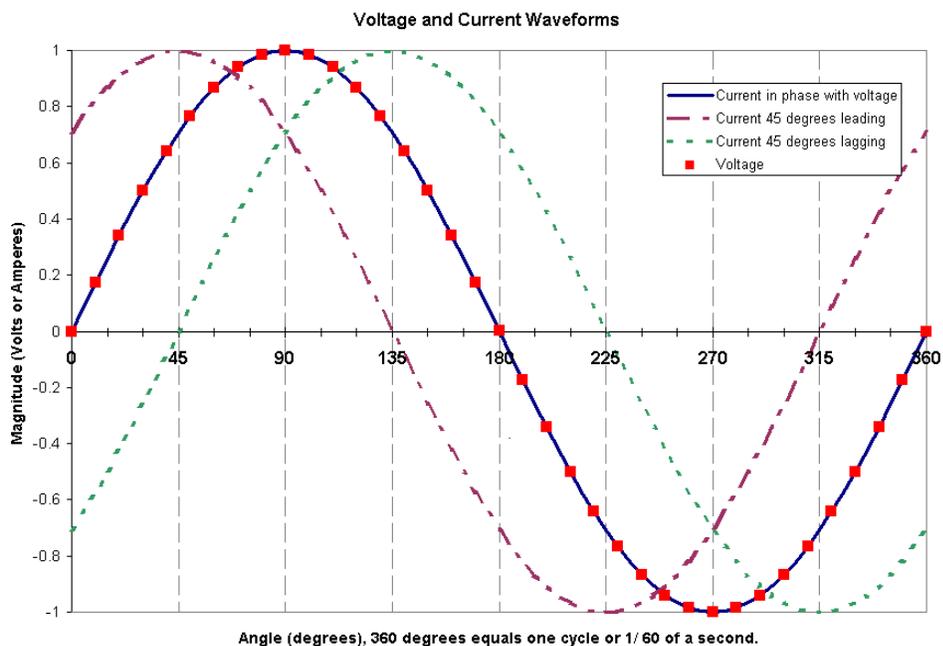
Source: FERC staff

Figure 7 is an example of a generator capability set, or curve. Due to the shape of the boundary, it is referred to as a D-curve. It has three components, labeled field heating limit, armature heating limit and core-end heating limit. The conductors on the armature are connected at the ends, and the core end (or end region) refers to these end connections. The generator prime mover is the turbine connected to the generator; the size of the turbine determines the prime mover limit. The prime mover is generally designed with less capacity than the electric generator. Because generators are almost always supplying or consuming some amount of reactive power to support system voltage, a turbine capable of delivering all of the mechanical power the generator can convert to electricity would be underutilized. The generator and turbine are separate pieces of equipment and may be upgraded independently; upgrading to a turbine with greater mechanical power output may extend the turbine constraint closer to the boundary of the D-curve.

Figure 7: Generator Capability Curve
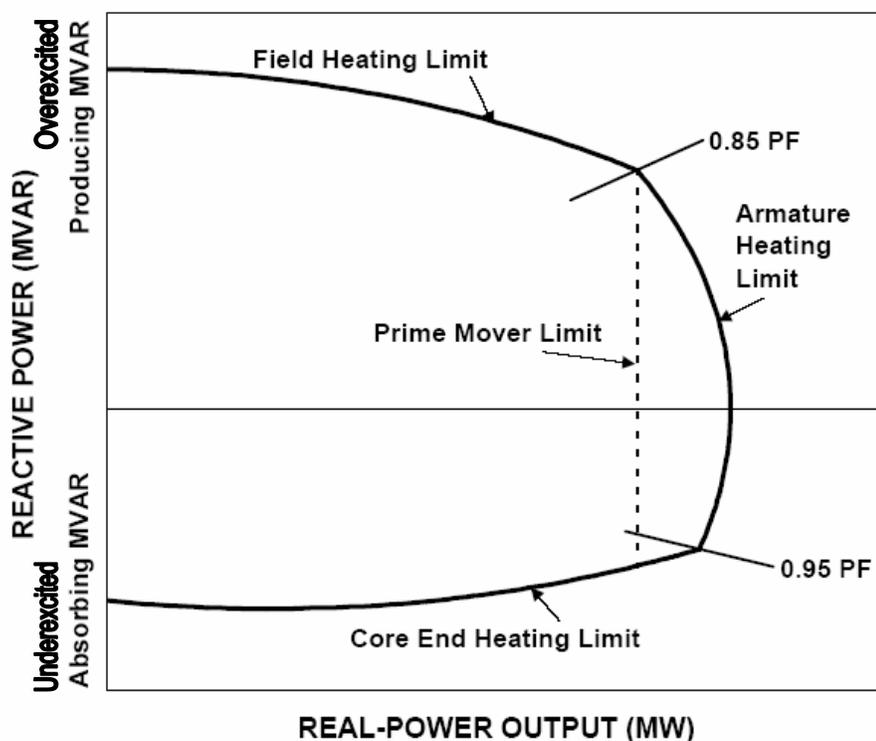
Source: B. Kirby and E. Hirst 1997, *Ancillary-Service Details: Voltage Control*, ORNL/ CON-453, Oak Ridge National Laboratory, Oak Ridge, Tenn., December 1997.

Principles for Efficient and Reliable Reactive Power Supply and Consumption

The capability-set limits are thermal limits for different parts of the generator. If the generator output approaches these limits, an alarm will notify the generator operator of the problem; if the operator does not bring the generator back to a safe operating point, the generator's protection scheme (relays, circuit breakers, fuses) will operate, resulting in disconnection of the generator from the network; finally, if the protection equipment fails and the operator does not act in time, the generator will overheat, potentially causing equipment damage. Because generators are expensive, generator operators generally will not operate the generator in a way that risks damaging the equipment and losing revenue during repair. At the edges of the D-curve, the opportunity cost of extending generator real or reactive power supply amounts to the millions of dollars that would be needed to replace damaged generator equipment and lost revenue during repair. The characteristics of the generator step-up transformer that connects the generator to the electric transmission system, as well as operational policies of the transmission system, may impose further limits on generator output.

Generator capability may be extended by the coolant used in the generator. A more efficient coolant allows the generator to dissipate more heat, thereby extending thermal limits. Most large generators are cooled with hydrogen; increasing the hydrogen pressure cools the generator equipment more effectively, increasing the generator's capability.

Figure 8 shows a hydrogen-cooled generator. The blue curve in Figure 9 is an example of a capability curve with different hydrogen pressures. Compressed hydrogen cools the generator three to four times as much as air, and water cools a generator 50 times as much as air. Water cooling is used only for large generators (300 megavolt amperes [MVA] or higher) because of the high cost of adding a water cooling system, which circulates water through pipes in the generator stator. Hydrogen cooling systems circulate hydrogen gas inside a case surrounding the entire generator. Some large generators have both water cooling pipes and hydrogen gas cooling.

Figure 8: **Hydrogen-Cooled Generator**

Source: Photo courtesy of Hitachi

Figure 9: **Generator Capability Curves at Different Hydrogen Pressures**
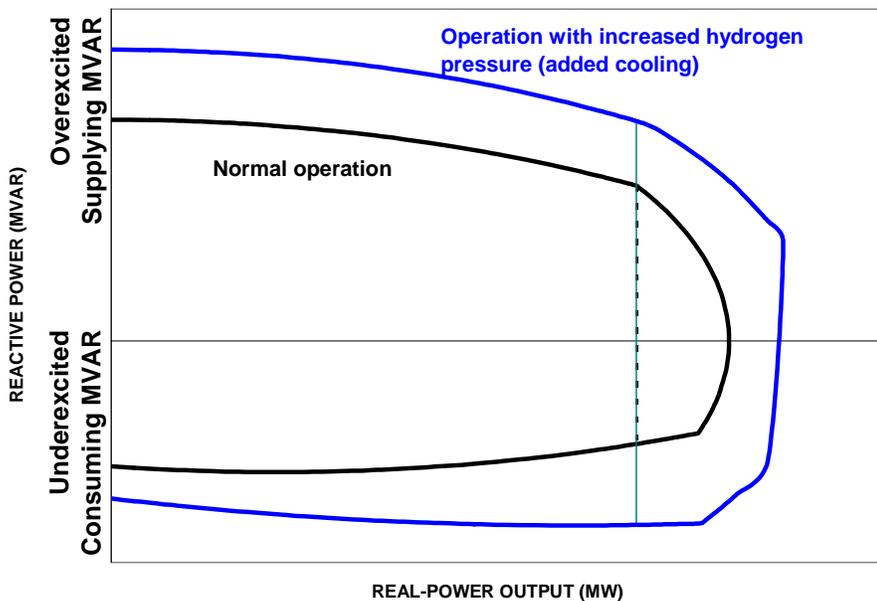
Source: Modified from B. Kirby and E. Hirst 1997, *Ancillary-Service Details: Voltage Control*, ORNL/CON-453, Oak Ridge National Laboratory, Oak Ridge, Tenn., December 1997.

History of Reactive Power Pricing

Historically, utilities designed transmission rates based on the costs of a plant booked to the transmission function. With regard to reactive power, transmission-only customers were assigned costs for reactive power support. Rate designs varied according to reactive power use or adjustments to a transmission customer's real power demand or energy consumption according to the customer's power factor. Reactive power then was related to the reliable operation of the transmission system and most utilities imposed penalties or rewards upon large customers whose power factor was below or above a threshold or trigger power factor. Furthermore, reactive power costs were embedded inside a "deadband."[17]

 In 1990, in *Northern States Power Company*,[18] the Commission found for the first time that a separate charge for reactive power was not inherently unjust and unreasonable. In a subsequent case again involving Northern States Power Co., the Commission set procedures by which utilities were to set unbundled wholesale prices for reactive power service.

Specifically, the Commission stated that:

> Northern States will be required to consolidate the total cost of all reactive power sources in the development of a proposed reactive power charge. . . . the utility will be required to identify the actual costs of the portion of the generator used in the production of reactive power. Northern States will also be required to identify and omit from the calculation of the base transmission rate the cost of transmission equipment dedicated to the production of reactive power. In this manner, the total costs associated with reactive power supply will be consolidated for the development of a single charge for this service, in recognition of the fact that reactive power is supplied by many sources throughout a utility's system. Based on the general methodology described above, Northern States will be free to propose either an average or an incremental rate design in a particular case. As always, the burden of proof will be on the utility to justify its proposed rate.[19]

Against this background, this chapter explores the evolution of the Commission's pricing policies for reactive power.

[17] A deadband is a range of activity that does not incur extra charges and is used to simplify rate design.

[18] Opinion No. 383, 53 FERC ¶ 61,027 at 61,107, *reh'g denied*, 53 FERC ¶ 61,306 (1990).

[19] *Northern States Power Company (Minnesota and Wisconsin)*, 64 FERC ¶ 61,324 at 63,386 (1993), *reh'g denied*, 74 FERC ¶ 61,106 (1996).

Order No. 888

In Order No. 888,[20] issued in 1996, the Commission concluded that six ancillary services, including "reactive supply and voltage control from generation sources service" (reactive power), must be included in an open access transmission tariff.[21] The Commission found that reactive power is necessary to the provision of basic transmission service within every control area. It explained that although a customer is required to take reactive power from the transmission provider or control area operator, a customer may reduce the charge for this service to the extent it can reduce its requirement for reactive power.[22]

The Commission further explained that there are two ways of supplying reactive power and controlling voltage: (1) installation of facilities, usually capacitors, as part of the transmission system; and (2) use of generating facilities. The Commission said that it would consider the costs of the first to be part of the cost of basic transmission service and, as such, would not be a separate ancillary service. As to the use of generating facilities, the Commission explained that this service must be unbundled from basic transmission service and would be considered a separate ancillary service.

Because the transmission provider must provide at least some reactive power from generation sources and because the transmission customer has the ability to affect the amount of reactive supply required,[23] the Commission required that reactive power must be offered as a discrete service and, to the extent feasible, charged for on the basis of the amount required. The Commission further stated that it would consider ancillary services rate proposals on a case-by-case basis.

With respect to the pricing of ancillary services, the Commission offered the following guidance: (1) ancillary service rates should be unbundled from rates for basic transmission service; (2) the fact that Commission has authorized a utility to sell wholesale power at market-based rates does not mean that it has authorized the utility to sell ancillary services at market-based rates; (3) in the absence of a demonstration that the seller does not have market power in such services, rates for ancillary services should be cost-based and established as price caps, from which transmission providers

---

[20] *Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. Regulations Preambles January 1991-June 1996 ¶ 31,036 at 31,705-06 and 31,716-17 (1996), Order No. 888-A, FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[21] Order No. 888 at 31,705. The pro forma open access transmission tariff (OATT) includes six schedules that set forth the details pertaining to each ancillary service. The details concerning reactive power are included in Schedule 2 of the pro forma OATT. Order No. 888 at 31,960.

[22] In this regard, the Commission recognized that the ability to reduce reactive power requirements will be affected by the location and operating capabilities of the generator. It asserted that any arrangement for the customer to self-supply a portion of reactive supply should be specified in the transmission customer's service agreement with the transmission provider.

(See next page for sidenote 23)

may offer a discount to reflect cost variations or to match rates available from any third party; (4) the amount of each ancillary service that the customer must purchase, self-supply or otherwise procure must be readily determined from the transmission provider's tariff and comparable to the obligations to which the transmission provider itself is subject (transmission provider must take ancillary services for its own wholesale transmission under its own tariff); and (5) the location and characteristics of a customer's loads and generation resources may affect the level of ancillary service costs incurred by the transmission provider (rates and billing units should reflect these characteristics to the extent practicable).[24]

Further, the Commission stated that:

> [s]eparation of reactive supply and voltage control from basic transmission service also may contribute to the development of a competitive market for such service if technology or industry changes result in improved ability to measure the reactive power needs of individual transmission customers or the ability to supply reactive supply from more distant sources.[25]

In Order No. 888-A, the Commission agreed to modify Schedule 2 to refer to generating facilities that are under the control of the control area operator instead of in the control area. The Commission emphasized that the control area operator must be able to control the dispatch of reactive power wherever it is located. It further stated that the transmission customer's service agreement should specify the generating resources made available by the transmission customer that provide reactive support. The Commission also agreed to modify Schedule 2 to allow a transmission customer to supply at least part of the reactive power service it requires through self-provision or purchases from generating facilities under the control of the control area operator. The Commission added that the transmission customer's service agreement should specify all reactive supply arrangements. The Commission denied a request that customer-owned generation facilities that are available to supply reactive power should automatically receive a credit. Finally, the Commission recognized that reactive power does not travel well and indicated that it would not require that the supply of reactive power be on a gridwide or regionwide basis because reactive power must be supplied near the point of need.[26]

In Order No. 888-B, the Commission rejected an argument that "under the control of the control area operator" refers only to generators with automatic voltage control. It clarified that what is under the control of the control area operator is the reactive production and absorption capability of the generator and not the generator's ability to produce real power. The Commission clarified that "simply supplying some duplicative ancillary services . . . in ways that do not reduce the ancillary services costs of the transmission provider or that are not coordinated with the control area operator does not qualify for a reduced charge."[27]

Post-Order No. 888 Cases

Opinion Nos. 416 and 440. Soon after the issuance of Order No. 888, the Commission was presented with the issue of how to calculate a generator-supplied reactive power charge. Two significant opinions, Opinion Nos. 416[28] and 440,[29] set forth the foundation for the Commission's resolution of this issue.

In Opinion No. 416, the Commission found that a reactive power charge in a situation in which the transmitting utility delivers power from generation located on its own system is consistent with Order No. 888 and is appropriate. However, the Commission rejected Southern Company Services Inc.'s proposed reactive power charge as unjust and unreasonable, and adopted an alternative methodology for determining a reactive power charge.

The Commission recognized that the failure to provide the correct amount of reactive power at various points on the transmission system can cause deviations from desired voltage levels and disruption in the flow of power on the system. The Commission noted that Southern's proposed reactive power charge at issue was intended to recoup the costs associated with using its generators to supply or absorb reactive power.

To quantify the incremental reactive power impact of the proposed transactions on the Southern system, Southern performed load-flow studies to determine the amount of additional reactive power supplied by Southern's generators to support the agreements at issue. To design the reactive power charge, Southern identified six generating components involved in the

[27] Order No. 888-B at 62,094.

[28] *Southern Company Services Inc.*, Opinion No. 416, 80 FERC ¶ 61,318 (1997), *reh'g denied*, Opinion No. 416-A, 82 FERC ¶ 61,168 (1998).

[29] *American Electric Power Service Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999).

production of reactive power: (1) the exciter; (2) the exciter cooling system; (3) generator stator; (4) rotor; (5) turbine assembly; and (6) step-up transformer. Southern assigned 100 percent of the cost of the exciter and the exciter cooling system to the reactive power charge and allocated the cost of the remaining items between real and reactive power based on a relationship of real and reactive power to apparent power, the nameplate power factor.[30] Southern then determined the cost of real power capacity and energy losses associated with the additional reactive power demand and divided the sum of the real and reactive power costs by the total amount of real power involved and levelized the reactive power charge over the contract term to produce a fixed annual reactive power charge.

The Commission determined that Southern's load-flow studies were not an appropriate measure of cost causation on the Southern system. The Commission explained that it would not allow the use of incremental costing for generator-supplied vars when the transmission charge (as well as the cost of transmission-related vars) is developed on a rolled-in basis.

The Commission found that a reactive power charge calculated by determining the annual cost of generator-supplied reactive power capability on the Southern system and dividing this cost by Southern's annual system peak load to be a reasonable approach. The Commission also rejected Southern's proposed heating loss component because Southern had not explained why the energy costs associated with the heating loss component are not already recovered through Southern's fuel adjustment clause.

The Commission further found that Southern's formula for allocating the costs of the generator stator, rotor and step-up transformer to be reasonable. With respect to the exciter system, the Commission determined that Southern should not be permitted to allocate the entire costs of these generator components to the reactive power charge, but should allocate these costs between real and reactive power in the same manner as the other costs described above. The Commission also rejected the inclusion of any turbine costs in the reactive power charge. It stated that "in contrast to other components that produce both real and reactive power, turbines produce only real power."[31]

[30] Apparent Power^2 = Real Power^2 + Reactive Power^2.

[31] Opinion No. 416 at 62,091.

The Commission's rejection of heating loss and turbine costs was appealed to the U.S. Court of Appeals for the District of Columbia. The court remanded to the Commission the turbine assembly costs for reconsideration and stated that the Commission should allow a recalculation of heating loss costs and should reconsider whether all heating loss costs are recovered.[32]

[32] *Alabama Power Co.* v. *FERC*, 220 F.3d 595 at 600-01 (D.C. Cir. 2000).

In Opinion No. 440, the Commission approved a methodology presented by American Electric Power Service Corp. (AEP) for generators to recover costs for reactive power. AEP identified three components of production plant that are directly related to the production of vars: (1) the generator and its exciter; (2) accessory electric equipment that supports the operation of the generator-exciter; and (3) the remaining total production investment required to provide real power and operate the exciter. Because these plant items produce real and reactive power, AEP developed an allocation factor[33] to segregate the reactive production function from the real power production function. AEP based this allocation factor on the capability of a generator to produce vars, where this capability is measured at the generator terminals. Once the plant investment associated with reactive power production is determined, AEP applied an annual carrying charge to these costs to determine an annual revenue requirement.

[33] AEP used the formula $Mvar^2 / MVA^2$ to determine the allocation factor.

Subsequently, in *WPS Westwood Generation LLC*,[34] the Commission standardized the methodology for reactive power compensation by indicating that all generators seeking reactive power recovery that have actual cost data and support should use the method employed in Opinion No. 440, i.e., the AEP methodology.

[34] 101 FERC ¶ 61,290 at 62,167 (2002) (*WPS Westwood*).

Revenue Requirement Filings by Generators. After Opinion No. 440, but prior to *WPS Westwood*, the Commission accepted a proposal by PJM[35] that revenue requirements of generation owners that are not transmission owners be included in the charges for reactive power and that reactive power-related revenues be allocated to all generation owners. As a result, many independent generators in PJM began to file rate schedules, under section 205, specifying their revenue requirements for providing cost-based reactive power. These filings generally followed the AEP methodology, i.e., inclusion of the fixed capacity component discussed above, but also included other components. The trend began with the Commission's acceptance of a filing by FPL Energy MH50 LP.[36] In its filing, FPL Energy included not only the

[35] PJM Interconnection LLC, Docket No. ER00-3327-000, September 25, 2000 (unpublished letter order).

[36] FPL Energy MH50 LP, 96 FERC ¶ 61,035 (2001).

fixed capability component in its revenue requirement, but also a heating losses component and a lost opportunity costs component. Subsequent filings that included a heating losses component[37] and often a lost opportunity costs component[38] were mostly accepted by delegated authority.[39] Recently, the FPL Energy model was adopted by generators in the Midwest ISO territory that filed rate schedules for reactive power,[40] and by generators seeking

Electrical Generator

Source: FERC image library

compensation under interconnection agreements with transmission owners.[41] The Commission has recently ordered hearing procedures for many of these filings from generators seeking to recover reactive power costs.[42] Because these filings have been made by nonutility generators, the Commission generally has allowed them to use proxy figures for their return on equity and overall rate of return based on the return on equity and overall rate of

[37] Generally, heating losses are described as significant losses through ohm heating associated with the armature winding and field winding of the generator. There are also heating losses through the generator step-up transformer.

[38] Lost opportunity costs are generally described as costs incurred in the event that a control area operator calls on a generator to curtail its real power output in order to provide reactive power. In other words, the opportunity cost is equal to the value of the reduced real power sale that resulted from increased reactive power provided to the control area operator.

[39] *See, e.g., Liberty Electric Power LLC*, Docket Nos. ER03-88-000 and ER03-88-001) (unpublished delegated letter order issued December 30, 2002); *Handsome Lake Energy LLC*, Docket No ER02-771-000 (unpublished delegated letter order issued March 8, 2002); *Bethlehem Steel Corp.*, Docket No. ER02-1894-000 (unpublished delegated letter order issued June 25, 2002); *Sunbury Generation LLC*, Docket No. ER02-2362-000 (unpublished delegated letter order issued October 22, 2002)

[40] *See Troy Energy, LLC,* 105 FERC ¶ 61,250 (2003) (*Troy Energy*); *Orion Power MidWest L.P.*, 107 FERC ¶ 61,216 (2004).

[41] *See, e.g., Tenaska Virginia Partners LP*, 107 FERC ¶ 61,207 (2004).

[42] *See, e.g., Duke Lee Energy, LLC,* 107 FERC ¶ 61,200 (2004); *Troy Energy.*

[43] Many of these filings usually cite to *City of Vernon*, 93 FERC ¶ 61,103 (2000), *reh'g denied*, 94 FERC ¶ 61,148 (2001) and *New England Power Pool*, 92 FERC ¶ 61,020 at 61,041 (2000) where the Commission accepted the use of such proxies in other contexts.

[44] *Michigan Electric Transmission Co.*, 96 FERC ¶ 61,214 at 61,906 (2001), citing *Consumers Energy Company*, 93 FERC ¶ 61,339 at 62,154 (2001), *order on reh'g*, 94 FERC ¶ 61,230 at 61,834 (2001).

[45] *Otter Tail Power Co.*, 99 FERC ¶ 61,019 at 61,092 (2002).

[46] *Michigan Electric Transmission Co.*, 97 FERC ¶ 61,187 at 61,853 (2001).

[47] *American Transmission Systems Inc.*, 97 FERC ¶ 61,273 at 62,162 (2001). *See also Cambridge Electric Light Co.*, 96 FERC ¶ 61,205 at 61.875-76 (2001) ("Since the transmission provider is responsible for the reliability of the system and any liability that might accrue due to a loss of reliability, we believe that it is in the best position to determine when a generator should be disconnected, either permanently or temporarily.").

[48] American Transmission; at 62,162; to date, the Commission has not addressed what these costs might be.

[49] *Detroit Edison Co.*, 95 FERC ¶ 61,415 at 62,538 (2001).

[50] *Consumers Energy Co.*, 94 FERC ¶ 61,230 at 61,834 (2001).

return percentages accepted by the Commission for the transmission owner to which they are interconnected.[43]

Other Compensation Issues With Generators. The Commission has stated that a generator need not be compensated for providing reactive power within its design limits and that providing reactive power within design limitations is not providing an ancillary service; it is simply ensuring that a generator lives up to its obligations.[44]

In addition, the Commission has stated that a transmission owner is not required to provide compensation to generators for reactive power if the generator is not under the control of the control area operator.[45] However, the Commission has found that to the extent a transmission owner is compensating an affiliate-owned generator for providing reactive power, it must also compensate other generators that provide reactive support to that system.[46]

Also, the Commission has stated that a transmission owner should have the right to call upon a generator to start up its generator, if possible, to provide reactive power during an emergency condition, but that the transmission owner should reimburse the generator for its out-of-pocket costs to start up its facility.[47] The Commission also stated that "if [a generator] refuses to supply reactive power in an emergency condition when it is able to do so, [the generator] should pay the costs that result from that refusal."[48]

Further, the Commission has stated that where the transmission provider requests a generator to increase or decrease reactive power output beyond that which the generator is required to provide, the generator must be compensated by the transmission provider.[49] The Commission has stated that generators are free to file ancillary service schedules to provide for compensation.

As to the reactive power that a generator has to provide, the Commission has found that it is just and reasonable for a generator to be required to provide equipment, at its own cost, to meet its reactive power obligations in order to interconnect to a transmission provider's system.[50]

With regard to qualifying facilities (QF) and whether they can be compensated for providing reactive power, the Commission has dismissed such filings because rates that QFs charge for reactive power are not subject to Commission review under section 205.[51]

Transmission Customers. In Order No. 888, the Commission abandoned the approach of having a ceiling rate of 1 mil per kWh ($1/MWh) for a package of three ancillary services, including reactive power. However, pre-Order No. 888 tariffs of many utilities use 1 mil per kWh as the rate for this ancillary services package. Figure 3.1 presents a sample of reactive power rates on file at the Commission.

Figure 3.1: **Examples of Reactive Power Charges in Tariffs**

Reactive Power Charges in OATT Schedule 2 for Selected Utilities	
COMPANY NAME	($/Kw-MONTH)
Duke Energy	$0.2000
Tucson Electric Power Company	$0.1610
Nevada Power Company	$0.1580
Black Hills Power	$0.1203
Dominion Virginia Power	$0.1100
Florida Power Corporation	$0.1100
Florida Power and Light	$0.1008
Sierra Pacific Power Company	$0.1000
Southwestern Public Service Company	$0.0940
Northern States Power	$0.0930
Carolina Power and Light Company	$0.0888
Bonneville Power Administration	$0.0670
Public Service Company of New Mexico	$0.0500
El Paso Electric Company	$0.0440
Portland General Electric Company	$0.0384
Public Service Company of Colorado	$0.0312
Puget Sound Energy	$0.0060
Arizona Public Service Company	No Charge
Idaho Power Company	No Charge
PacifiCorp	No Charge

Source: Current OATTs on file with the Commission.

[52] *Atlantic City Electric Co.*, 77 FERC ¶ 61,144 at 61,537 n.22 (1996).

[53] Order No. 888 at 31,715-17 (1996).

[54] *See, e.g., Delmarva Power & Light Co.*, 78 FERC ¶ 61,060 at 61,220 (1997); *Alliant Services Inc.*, 84 FERC ¶ 61,252 at 62,250 (1998).

[55] *Maine Public Service Co.*, Opinion No. 434, 85 FERC ¶ 61,412 at 62,566 (1998).

[56] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003), FERC Stats. & Regs., Regulations Preambles ¶ 31,146 at P 21 (2003) (Order No. 2003), *order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (March 26, 2004), FERC Stats. & Regs., Regulations Preambles ¶ 31,160 (2004) (Order No. 2003-A), *order on reh'g*, 109 FERC 61,287 (2004) (Order No. 2003-B).

[57] Order No. 2003, section 9.6.1. *See also Florida Power & Light Co.*, 108 FERC ¶ 61,239 (2004).

[58] Order No. 2003-A, 416.

Service agreements can provide that transmission customers will supply their own reactive power and voltage control service.[52] As was explained in Order No. 888, although the pro forma tariff states that the transmission provider must provide and the transmission customer must take reactive power and voltage control service, the amount taken from the transmission provider would be net of any amount furnished by the customer.[53] This would be reflected in the service agreement that addresses the amount of ancillary services the customer is purchasing from the transmission provider. The Commission has also stated that requests for reactive power credits must be specific and supported by a demonstration of exactly how much reactive power the customer will supply.[54]

The Commission has stated that the costs of generator step-up transformers (GSU) should be assigned directly to its related generating unit, not rolled into transmission rates.[55]

Order No. 2003. In Order No 2003,[56] the Commission emphasized that an interconnection customer "should not be compensated for reactive power when operating its generating facility within the established power factor range, since it is only meeting its obligation." However, the Commission required the transmission provider or RTO/ISO to compensate the interconnection customer for real and reactive power or other emergency condition services that the interconnection customer provides to support the transmission system during an emergency situation. In Order No. 2003, the Commission also stated that the "Interconnection customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the point of interconnection at a power factor within the range of 0.95 leading (producing) to 0.95 lagging (absorbing), unless transmission provider has established different requirements that apply to all generators in the control area on a comparable basis."[57]

In Order No. 2003-A, the Commission clarified that if the transmission provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the interconnection customer.[58]

In the rehearing requests to Order No. 2003-A, generators requested the Commission to clearly establish and enforce the principle that interconnection customers have a right to be compensated for providing reactive power both within and outside the bandwidth regardless of the compensation arrangements that may exist between the transmission provider and its affiliate. In Order No. 2003-B, the Commission clarified that Order 2003-A does not prejudge how the interconnection customer is to be compensated for providing reactive power. It notes that such payments are to be provided under a filed rate schedule unless service is provided under a Commission-approved RTO or ISO tariff.[59]

[59] Order No. 2003-B at P 120.

Reactive Power and RTOs and ISOs

PJM Interconnection LLC, New York Independent System Operator Inc. (NYISO), ISO-New England Inc. (ISO-NE), Midwest Independent Transmission System Operator Inc. (Midwest ISO), California Independent System Operator Corporation (CAISO) and Southwest Power Pool Inc. (SPP) use a variety of methods to compensate generators for reactive power and to charge customers for the provisions of reactive power.

Compensation to Generators. With the exception of CAISO, the RTO/ISOs provide compensation to generators for providing reactive power under Schedule 2 of their tariffs.

Under PJM's Schedule 2, PJM compensates all generators (affiliates of vertically integrated utilities and IPPs) with a payment equal to the generation owner's monthly revenue requirement as accepted or approved by the Commission. In order to qualify for Schedule 2 compensation, generators have to be under the control of the control area operator and be operated to produce or absorb reactive power. PJM also provides lost opportunity cost payments when there is a reduction in real power output. The other ISOs that use Schedule 2 generally compensate generators in a similar fashion albeit with some slight variations.

Midwest ISO's Schedule 2 compensates generators owned by transmission

owners for providing reactive power, but provides no mechanism to compensate IPPs for providing this service. The rates for reactive power are based on the control area operator rates on file with the Commission and are paid where the load is located, i.e., on a zonal basis, while loads located outside Midwest ISO are charged an average systemwide rate. Midwest ISO's compensation for reactive power is a pass-through of the revenues collected by individual control area operators providing the service. Also, Midwest ISO does not provide for lost opportunity costs.

NYISO's Schedule 2 provides compensation for all generators that provide reactive power. However, generators owned by utilities are compensated differently from nonutility generators operating under power purchase agreements. Moreover, generators owned by utilities are also compensated differently based on whether they are under contract to supply installed capacity.Generators that provide voltage support service receive an equal annual payment from a pool that consists of the total costs incurred by all generators, in that year, that provide voltage support service. The NYISO outlines these payments in its 2004 Voltage Support Service Rate Schedule. The rate for the generators in 2004 is derived by dividing the annual 2002 program cost ($61 million) by the 2002 generation capacity expected (15,570 Mvar), which provides a compensation rate of $3,919/Mvar per year.

NYISO also provides for lost opportunity costs and penalties for failing to provide reactive power. In order to qualify for compensation under NYISO's Schedule 2, a generator has to pass a capability test performed by NYISO.

ISO-NE's Schedule 2 compensates generators for providing reactive power based on four components: (1) capacity cost; (2) lost opportunity cost; (3) cost of energy consumed; and (4) cost of energy produced. ISO-NE does not provide penalties for a generator's failure to provide reactive power. In order to qualify for compensation under ISO-NE's Schedule 2, a generator must be in the ISO-NE market system and provide measurable voltage support.

SPP's compensation for reactive power is a pass-through of the revenues

collected by individual control area operators.

While CAISO does not have a Schedule 2 in its tariff, the CAISO tariff states that generators receive no compensation for operating within a specified power factor range. If the CAISO requires additional reactive power, it procures this either through reliability must-run (RMR) contracts or, if no other sources are available, by instructing a generator to move its reactive power output outside its mandatory range. Only if the generator must reduce its real power in order to comply with such an instruction will it be compensated, i.e., lost opportunity costs.

Power Factor Range. As discussed above, Order No. 2003 established that an interconnection customer can receive compensation for providing reactive power when its generator provides reactive power outside of the power factor range of 0.95 leading (producing) and 0.95 lagging (absorbing), or the power factor range established by the transmission provider. PJM requires a power factor range of 0.95 leading and 0.90 lagging. CAISO also has the same requirement for generators that do not operate under reliability must run agreements. All participating generators in CAISO that do operate under such agreements, however, are required to operate within the power factor range specified in their agreements.

Reactive Power Testing. Midwest ISO, NYISO and ISO-NE have established their own power factor criteria requirements. Testing requirements vary. The NYISO requires that generators perform a reactive capability test once a year to determine how much they can provide for the ISO. In ISO-NE all generators must initially conduct a full lagging reactive power demonstration test. The test is repeated every five years to determine leading and lagging reactive power capability. SPP does not have specific requirements in place, but is seeking to develop RTO-wide criteria for generators. Until the criteria are set, generators in SPP negotiate with individual control areas to provide services based on their reactive power capability. Similar to SPP, in Midwest ISO individual control areas negotiate with generators to fulfill the need for reactive power in their regions.

Reactive Power Charges for Transmission Customers. The charges that transmission customers pay for reactive power are included in the ISO/RTO specific Schedule 2. When a transmission customer requests to purchase reactive power from PJM, NYISO or ISO-NE, charges are based on the monthly charges incurred. SPP and Midwest ISO do not have a formula rate but pass through reactive power charges from the control area operator. Under the CAISO tariff, scheduling coordinators (transmission customers) are billed for the costs incurred under the RMR contracts.

International Reactive Power Markets

There are several market designs throughout the world for reactive power that have developed in the recent past. The mechanisms include requirements, contracts and real-time prices. In this chapter we describe the market designs for reactive power in several Canadian provinces and several countries.

Reactive Power Markets in Canada. In Canada each province determines its own electricity policy and hence, regulatory practices as they relate to the provision and compensation for reactive power. Ontario and Alberta have independent system operators.

In Ontario, all generators of more than 10 MW connected to the grid controlled by the Independent Electric System Operator (IESO – formerly the Independent Electric Market Operator, or IMO) are required by the market rules to have the capability of supplying at their terminals reactive power in the range of 90% lagging (injecting into the system) and 95% leading (absorbing from the system) based on the rated real power at rated voltage. The generators must be capable of operating continuously at full output within +/- 5% of the generator's rated terminal voltage. The generators are not required to operate continuously outside this voltage range to satisfy reactive power requirements.

Generators who have signed ancillary service contracts for reactive support and voltage control are compensated for the incremental costs from energy losses incurred by running at non-unity power factor or costs of running as synchronous condensers at the IESO's request. They are also compensated for their lost profits if directed to provide reactive capability outside the market rule requirement range.

Shunt reactive compensation, primarily switched capacitors or reactors, is installed by the transmission owner(s) to meet the forecast reactive power requirements as part of their transmission investment programs.

In Alberta, generators may be penalized if they are not capable of producing or absorbing reactive power within a 0.90 lagging and 0.95 leading power factor range. These penalties can constrain MW output for a specific period

(e.g., six months). In transmission constrained areas where generators provide "transmission must run" service, the contracts include compensation for reactive power.

In Manitoba, generators are compensated when they provide reactive power capability outside of the normal range specified in the Transmission System Interconnection Requirements. The compensation mechanism is defined in the interconnection tariff and is based on generators verifiable costs to provide the extra reactive power.

In Québec and British Columbia, the Open Access Transmission Tariff treats reactive support and voltage control as an ancillary service. The cost of providing this service is recovered from the transmission customer and paid to the suppliers. Beyond this there are neither incentives nor penalties for the provision of reactive power.

Reactive Power Markets in Europe. In Great Britain, in the early 1990s, after privatization and corporate unbundling of generation, transmission and distribution, the England-Wales market started with a cost-reflective (cost-based) approach to paying generators for reactive power. Since the mid-1990s, a market-oriented approach to reactive power has evolved. Generators with a capacity greater than 50 MW are required to have a 0.95 leading power factor to a 0.85 lagging power factor capability at the high voltage side of the generator step-up transformer. After extensive consultation with market participants, metering and monitoring rules were established and new dispatch rules were developed.

The National Grid Co. (NGC), which is both the system operator and the transmission owner, sends the generator a dispatch signal consisting of the amounts of real power and reactive power within a range of the required generator capability. A generator can accept a default payment for reactive power of approximately $2.40/Mvarh leading or lagging, or as an alternative, the generator may offer contracts with a minimum term of one year. The offer consists of three parts: a synchronized capability price in £/Mvar, an availability capability price in £/Mvar and a utilization price in £/Mvarh. The grid company assesses the offer, historical performance and effectiveness of each generator against its locational forecast needs in about

20 electrical zones to decide which offers to accept. This provides generators incentives to offer capability beyond the requirements, lowering investment requirements for the transmission system.

The NGC has financial incentives to keep congestion low. Since 1990 the company increased its transmission reactive power capacity from about 3,000 Mvars to about 19,000 Mvars of mechanically switched capacitors, 9,000 Mvars of SVCs and 4,000 Mvars of Quadrature Boosters (similar to phase shifters) in 2004. Some of the SVCs can be relocated by truck in about eights months. In contrast to conventional approaches, NGC relocates some of the transmission assets in order to target areas in need of relief. Twenty percent of the reactive power supplied is from generators.[60] Since 1993, through a combination of contracting with generators, operational improvements, improved forecasting and investments in transmission, NGC has reduced congestion costs, as defined by the regulator, by 90%.[61]

In Sweden, most of the generation (primarily hydro) is located in the north while the transmission system carries the power to the south where most of the load is located. Reactive power, which is supplied mostly in the south, is supplied on a mandatory basis and there is no compensation. The goal is to keep reactive power flow on the transmission system close to zero, especially at certain interfaces. Some large generators are seldom used for voltage control and are operated at a constant reactive power output. Hydro and thermal units are required to maintain a capability to inject reactive power of one third the amount of active power injection (a power factor of approximately 0.90). Network operators use as much static reactive power as possible.[62]

In the Netherlands, the network companies have local reactive power requirements. These companies purchase reactive power locally through bilateral contracts with generators or through exchange with other network companies. Generators contracted for the reactive power service are paid for their reactive power capacity only. No payment is made for reactive power supplied.[63]

The Belgian Independent System Operator has a transmission tariff for reactive power and voltage regulation that has a small charge per Mwh for

[60] Julian Cox, National Grid Co., presentation to FERC staff, October 25, 2004.

[61] S. Oren, G. Gross and F. Alvarado, "Alternative Business Models for Transmission System Investment and Operations," 2002, http://www.eh.doe.gov/ntgs/gridstudy/MAIN_3.PDF, 10.

[62] John D. Kueck, Brendan J. Kirby, Leon M. Tolbert and D. Tom Rizy, Voltage Regulation with Distributed Energy Resources (DER), Oak Ridge National Laboratory, Oak Ridge, Tenn., draft, received November 4, 2004.

[63] J. Zhong, and K. Bhattacharya, "Reactive Power Management in Deregulated Electricity Markets - A Review," *IEEE Power Engineering Society Winter Meeting*, 27-31 Jan. 2002, pp. 1287-1292.

a specified power factor range and a much higher charge outside of this range. In the power factor range 0.95 leading to 0.95 lagging, for power greater than 10% of the contracted real power, the reactive power charge varies with voltage of the point of interconnection to the transmission network. In the transmission network the charge is 0.21 Euro/MWh ($US 0.27). At the network side of transformers into the medium voltage distribution network, the tariff is 0.23 Euro/MWh ($US 0.31). For reactive power outside the 0.95 leading/lagging power factor range, the charge is 6 Euro/Mvarh ($US 7.83). When the real power is less than 10% of the contracted amount, the lower charge applies for reactive power up to 32.9% of the real power, and the 6 Euro/Mvarh charge applies if reactive power is above 32.9% of 10% of the contracted amounts.[64]

Reactive Power Markets in Other Countries. The Australian ISO provides reactive power compensation to generators and synchronous condensers. For the generators there are mandatory capabilities (0.9 lagging and 0.93 leading) and compensation for accepted offers of higher capabilities. The providers receive an availability payment, an enabling payment when dispatched and a compensation payment when their generators are restrained from operating according to market conditions. The voltage control sequence is generally as follows: capacitors and SVCs are switched on; reactive power is provided from generators where real power output is not constrained; in specific areas, synchronous compensators are called from a merit order depending on price; real power generation is constrained; and, lastly, market trades are curtailed.[65]

In India, the state electricity boards (similar to load serving entities) were drawing large amounts of reactive power from the EHV grid, causing 20% voltage drops on the 400-kV system, avoidable transmission losses and considerable reactive power from generators. The Indian regulator put a 4 paise/kvarh (approximately $1/Mvarh) price (buy and sell) on reactive power when the voltage dropped below 97% of nominal. In off-peak periods the charge is reversed when the voltage goes above 103%. All low voltage problems have now vanished.[66]

In Japan, Tokyo Electric Power Company (TEPCO) gives their retail customers the financial incentive to improve their power factor. It comes in

[64] ELIA System Operator S.A. Tariffs 01-01-2005 – 31-03-2005, Table 8: Tarif du réglage de la tension et de la puissance réactive (Tariff for voltage regulation and for reactive power), 21 December 2004, available at http://www.creg.be/pdf/Tarifs/E/ESOFR-01012005-31032005.pdf

[65] John D. Kueck, Brendan J. Kirby, Leon M. Tolbert and D. Tom Rizy, "Voltage Regulation with Distributed Energy Resources (DER)," Oak Ridge National Laboratory, Oak Ridge, Tenn., draft, received November 4, 2004, and J. Zhong, and K. Bhattacharya, "Reactive Power Management in Deregulated Electricity Markets – A Review," *IEEE Power Engineering Society Winter Meeting*, January 27-31, 2002, 1287-1292.

[66] Fax from Bhanu Bhushan, employee of the Indian National Grid Co., to Mark Lively, October 14, 2004 and email from Sushial Soonee, employee of the Indian National Grid Co., to Mark Lively dated October 20, 2004.

the form of a discount of the base rate. The discount is based on the customer's power factor. The electricity rate is a two part tariff: Base Rate + Electricity Rate, where

> **Base Rate = (Unit Price [Yen/kW])*(Contract kW)*(1.85-Power Factor)**
> **Electricity Rate = (Unit Price [Yen/kWh])*Total Usage [kWh]**

Unit Price for Base Rate is about US10$/kW and Unit Price for Electricity Rate is about US10¢/kWh. This program results in load installing equipment to increase its power factor and hence, reduce the base rate. Under this tariff the average customer power factor is 0.99.[67]

In Argentina, generators, transmission operators, distribution operators, and large loads have obligations to serve reactive power. Generators are required to produce and consume reactive power within the limits of their capability curves (D-curves). Transmission operators are required to maintain voltages within +/-3% for 500 kV and +/-5% for 220 kV and 132 kV. There are two levels of sanctions for failure to comply with the requirements. If the outage

[68] Argentina. Energy Secretary. Resolution SE 0106/2002. Official Bulletin no 29.899, May 16, 2002, pp. 8-10. "ANEXO 4: CONTROL DE TENSION Y DESPACHO DE POTENCIA REACTIVA", (Appendix 4: Control of voltage and dispatch of reactive power), available at http://www.enre.gov.ar/web/bibliotd.NSF/04256380006cf0060425636f00508108/57abd18e0397241403256bbb0044b849?OpenDocument

is announced in advance, there is a reactive power charge. There is an additional penalty if the outage is unannounced. Additionally, if an uncommitted generation unit is dispatched as a result of a reactive power shortage, the parties responsible for the shortage must pay the generator its startup costs. The penalty for an announced generator outage is the operations and maintenance cost of substitute equipment and a reactive power charge of Argentine $0.45/Mvarh ($0.15 US). If a generator outage is expected to last for more than one season, the generator may elect to install capacitors or reactors, as appropriate, to avoid the penalty charge. If an outage is announced a day or a week in advance, the penalty charge is Argentine $4.50/Mvarh ($1.50 US). If the outage is not announced in advance, the penalty charge applies for all hours the generator is in service or on reserve for the season. Generators that do not comply with reactive power requirements may be denied access to the system. The penalty system for transmission operators is similar to that of generators, with penalties charged per Mvar and based on the conceptual hourly compensation for lost load. Distribution operators and large loads are charged similar to generators, based on the replacement equipment operation and maintenance costs.[68]

Existing Reactive Power Issues

The existing reactive power market framework originates from the historically vertically integrated approach to electricity generation, transmission and distribution based on the view that the industry was a natural monopoly and subsequent regulatory policy changes to require open access. This chapter details some of the existing issues and potential problems with existing approaches to reactive power pricing and procurement. Because reactive power can be supplied or consumed by most assets in the electrical system, a comprehensive look should be made regarding the current incentives that exist to encourage reliable, efficient investment choices among generation, transmission and load. There are several problems and concerns regarding the current procurement practices and pricing policies for reactive power. These include a lack of transparent planning standards, noncompetitive procurement, discriminatory compensation policies, rigid interconnection standards that may not meet local needs and poor real-time incentives for production, consumption and dispatch.

Planning and Design for Reactive Power Issues

Existing system designs rely on both detailed system studies and engineering rules of thumb or good utility practice for new generation requirements regarding reactive power capabilities. System operators and regulators require the supply of reactive power within specified power factors, or operational bands, for interconnection. Outside of the specified power factors, generators may be paid opportunity costs for the supply of additional reactive power in independent system operator (ISO) markets. When the supply of available reactive power resources is deemed deficient, system operators rely on the system planning process to identify the investments needed to satisfy the system's reactive power needs.

1. Transparent and Consistent Reactive Power Planning Standards. Consistent and transparent planning standards for the overall reactive power system needs do not exist. Guidelines for dynamic and static reactive power requirements on the transmission system can differ from one system to another. The lack of such standards is a source of concern because of the public good characteristics of reliability. Reactive power is needed to ensure reliability, but because reliability is a public good, the harm from procuring

inadequate reactive power capability is not fully borne by a given transmission provider. As a result, transmission providers may not have the incentive to procure adequate reactive power capability. Consistent, enforced national planning standards might help to address this issue. In addition, the process used by many transmission providers, especially those outside of regional transmission organizations (RTOs) and independent system organizations (ISOs), for identifying potential system needs and developing alternative solutions is not transparent. As a result, it is difficult for the public to determine whether transmission providers procure reactive power and reactive power capability from the lowest-cost sources.

NERC, the North American Electric Reliability Council, sets reliability standards for system operations and planning and monitors compliance with these standards.[69] Each control area has a reliability coordinator who has the responsibility of conducting reliability planning analysis and monitoring reliability in operations; this may be the system operator, the control area operator or a separate entity. NERC Operating Manual Policy 9, "Reliability Coordinator Procedures," states that reliability coordinators are responsible for next-day planning, including reactive reserves, having situational awareness of reactive reserves and communicating problems with reactive reserves to control area operators, transmission operating entities and other reliability coordinators in real-time. NERC Planning Standard I.A, Table 1 lists the required system performance for loss of load under increasingly severe contingencies. Not providing enough reactive power to meet these standards is a violation, but there are currently no strong penalties for violating NERC standards. NERC has a new operating standard for Voltage and Reactive Control, proposed to take effect in April 2005. This standard requires transmission owners to maintain voltages within established limits, to maintain reactive reserves to keep voltages within acceptable limits following a single contingency and that transmission operators be able to direct the operation of devices necessary to regulate transmission voltage and reactive flow. The standard also requires generators to keep transmission operators informed of generator reactive power capabilities and generator voltage regulation equipment status.

Although standards exist, they are not specific. Because of the lack of clear standards for reactive power reserve requirements and because a transmission

[69] NERC Version 0 Reliability Standards – Operating Standards, Standard VAR-001-0 – Voltage and Reactive Control, NERC, October 25, 2004, available at http://www.nerc.com/~filez/standards/Version-0-RF.html.

provider may not bear the full reliability costs of inadequate reactive reserves, transmission providers may procure insufficient reactive power reserves. Of course, cost-of-service regulation may tend to offset the incentive to under-procure reactive power capability, because a transmission owner could increase its return by adding equipment providing reactive power capability to its rate base. However, these incentives to add equipment reactive power capability are largely negated in those cases where states have imposed rate freezes and regulatory disincentives for additional investment, since the costs and return from investing in additional resources cannot be recovered from customers.

2. Noncompetitive Procurement of Reactive Power Needs. In addition to the lack of transparent standards for reactive power needs existing as a barrier to efficient supply of reactive power, the regulatory processes may provide incentives for system operators not to adequately consider all available alternatives in the procurement of reactive power capacity. Reactive power continues to be procured primarily as a cost-of-service product. The cost-of-service model generally rewards capital investment, but not necessarily efficient contracting with nonaffiliated sources. If a vertically integrated utility buys power at a lower cost than can be produced internally, there is little or no reward. If the same capacity is built at a higher cost and put in the rate base, the vertically integrated utility is usually rewarded with a risk-adjusted return on equity that is often disproportionately high compared to the risk. The result is often inefficient and more expensive rate base investments. Historically, utilities have resisted buying power from third parties (other than affiliates), arguing that such purchases are incompatible with system reliability.

Once the system operator can identify and define the reactive power products that are needed to maintain system reliability, an opportunity for all suppliers to meet those needs should be made available. Those that supply reactive power products should be paid for the reactive power services provided. For instance, smaller mobile sources of reactive power can be placed to meet incremental system needs at times in which large traditional investments can be economically postponed while maintaining reliability. Some have argued that these resources are ignored because the system operator has little incentive to use available tools that may reduce the ability of the operator

to place additional assets in rate base.

3. Discriminatory Payments to Reactive Power Generation Sources. Some generation resources that provide reactive power capacity to the grid are not compensated while others that provide similar service receive cost-of-service payments. In non-RTO markets, payments for reactive power to generation resources are often limited to affiliate resources. The argument against nonaffiliate payment is based on the planning process of the transmission owner. The transmission owner claims that nonaffiliated resources are not part of the transmission planning process and the reactive power obligations are needed primarily to maintain the reliability of the existing system and do not provide any additional system-wide benefit. Further, determinations of public convenience and necessity generally do not address reactive power needs specifically. The process to determine the validity of such claim against systemwide needs or benefits is not transparent and has the potential for abuse. The payment of affiliate generation resources for reactive power capability, while denying nonaffiliate suppliers that provide useful and needed reactive power capability to the system is discriminatory. Payments for reactive power capability are not being made in a comparable manner to the suppliers that provide similar service under such regime.

Under Order 888, transmission service generally contains a charge for the supply of reactive power. A question arises as to whether unaffiliated generation is adequately compensated for both its reactive power capability and its supply of reactive power to the system. Comparability is required by a transmission owner toward its own and other interconnected generation. The ISO issues and pricing are relevant in the non-ISO markets along with this comparability requirement.

Several issues arise regarding which generation units should be eligible for reactive power payments. An argument is sometimes made that generation developed as part of "the system-planning process" should be eligible for reactive power compensation, while unaffiliated projects provide no such value to the system. New generation resources are required to provide reactive power by the Large Generator Interconnection Procedures. Further, as transmission owners continue to purchase unaffiliated facilities, there

exists the possibility that these investments receive reactive power compensation whereas the former unaffiliated suppliers were rejected for such compensation.

4. Appropriateness of Existing Payment Structure for Generation Supply.
Chapter 3 reviewed the history of reactive power pricing. The compensation to generators has been based on a formulaic approach that may have little relationship to the costs associated with the supply of reactive power capability and real time supply. For instance, the allocation factor used in the AEP methodology does not directly relate to the incremental investment cost in providing reactive capability or supply. Methods that attempt to allocate the fixed investment costs of a generator among the joint products that it produced (i.e., real and reactive power) inherently have some degree of arbitrariness. While this may have been appropriate in the cost-based paradigm it may need to be reexamined under a market-based approach. Such a re-examination is especially appropriate when eligibility for such payments may be determined, in part, by market participants and potentially provide an unfair competitive advantage.

Investment that results in reactive power capability by generation resources is driven by interconnection requirements, historical inertia and potential cost recovery for capacity. There is little interaction between the actual system need or value of reactive power capability and its supply by independent generation resources. For instance, there appears to be little empirical rigor to support the existing standards of interconnecting generation power factor requirements. Additionally, cost-of-service methodologies and payments for reactive power capability may have little relationship to the value of reactive power capability to the transmission system. Generators in some markets are uniformly provided a payment based on capital cost to supply reactive power based on the Opinion 440 (American Electric Power Inc., or AEP) Methodology. The Opinion 440 methodology provides a regulatory formula that allocates a portion of fixed costs that are paid by the transmission system customers. The requirements and costs that result have little or no relationship to the need for this capability. Some locations may have higher reactive power needs, and mechanisms to promote additional investment in reactive power capability may be applicable in those areas.

Alternative market solutions to provide needed reactive power capability may be available, but these options are not being adequately considered under the approaches currently pursued. Allowing the system operators' identified reactive power needs to be procured and paid for through more appropriate mechanisms should encourage more efficient supply of the resources needed to support the network operation.

5. Lack of Compensation to All Suppliers of Useful Reactive Capability. While transmission-based suppliers of reactive capability receive compensation, many generation-based suppliers are not compensated for reactive power capability that aids in system reliability. Compensating all market participants for the value of reactive power that they provide should encourage an adequate and efficient supply of reactive power. This is particularly true for generation resources that are relied upon to provide dynamic reactive power reserves. That is because it is unlikely that an entity will invest in and offer to supply reactive power capability unless it expects to recover its costs and earn a profit. Of course, many generators are able to earn revenues from sources other than reactive power - such as from sales of real power. Thus, much generation investment would continue to be made even if generators are not paid for providing reactive power capability. However, failing to pay generators for reactive power could reduce the amount of generation investment, particularly in areas where reactive power capability is very valuable to the system. That is, some efficient generation investment might not be built or might retire early without reactive power payments because revenues from real power sales and other sources, by themselves, would not be sufficient to cover the project's costs and return a profit. Failing to pay for reactive power supplied by generation resources also could reduce the amount of reactive power capability installed in new generation equipment. Developers may elect not to add reactive capability beyond the minimum requirements if they are not going to receive any additional revenue from doing so.

6. Rigid but Imprecise Generation Interconnection Standards. Interconnection standards generally require a standardized generation power factor for new generation. While these standards provide independent criteria for generation interconnection, local needs can vary from the standards. Some locations may have higher reactive power needs than the

standard, while other locations may have smaller needs.

The existing interconnection standards are imprecise in two important respects. The standards do not specify on which side of the step-up transformer the power factor is to be measured. Secondly, there is no standard for exactly how the power factor is to be measured.

Real-Time Reactive Power Demand Issues

Reactive power is required by two types of customers. First and primarily, reactive power is needed by the system operator to maintain voltage levels and ensure the reliability of the transmission network. Second, reactive power is supplied and consumed in varying amounts by most market participants. The combination of the system operator's need for maintaining system reliability and reactive power consumption by real power load determines the total system reactive power needs. Reactive power is defined in Order 888 as an ancillary service. As such, market participants often pay for reactive power through the applicable transmission service tariff.

1. System Operator Real-Time Reactive Power Needs. Reactive power is used to maintain the voltages in the network and is used by electricity customers, known as load, by power generation and by transmission owners. The system operator determines the voltage levels of the system to maintain reliability and promote efficient use of the system. Determining system needs for reactive power at any given time is a combination of the power system configuration; system operator decisions regarding voltage levels; the consumption of reactive power by load, transmission and generation; the consumption of real power by load; and the location of real-power supply.

Reactive power reserves are needed by the system to prevent voltage collapse. While reactive power supply from transmission elements is useful in reliably providing needed reactive power supply in most times, it is less useful providing reactive power supply in critical times when reactive power is needed to prevent voltage collapse. At these times, reactive power from generators and synchronous condensers are needed to provide critical supplies of dynamic reactive power. This reactive power capability will generally go unused but is deemed critical to ensure the long-run reliability

of the transmission network. It follows that the presence of this reactive power capacity and supply is critical in maintaining system reliability and might be viewed as a distinct product.

A system's real-time reactive power supply needs are, in part, determined by the voltage schedule provided by the system operator. System operators have flexibility in determining the voltage schedule across the system. These choices are not fixed and changes may increase or decrease the reliability and economic performance of the system. To date these decisions and the factors that drive the decision may vary considerably among system operators. The system operator, by adjusting voltage schedules can adjust the required supply of reactive power. Further, the system operator's scheduling decisions will also determine the availability of reactive power reserve capability.

At times, there may be insufficient supply of reactive power to maintain a desired voltage level and the system will be operated at a lower level of reliability. Similarly, a system operator may encounter a situation where the reactive power supply is available, but only at the cost of backing down needed real power supplies. In these cases, the system operator can either curtail real load or run at slightly lower voltage levels. A system operator may choose at times to run at slightly lower voltage levels rather than curtail real load. Thus, there can be a tradeoff between maintaining a specific reliability level and procuring reactive power at the cost of serving real power load. Similarly, the system operator has a choice between relying heavily on dynamic reactive power from generators or using nongenerator reactive power resources and saving dynamic generator capability as reserves in case of a system emergency.

Unlike real power reserves, which have a specific reserve margin requirement in each region of the country, there is no clearly defined requirement for reactive power reserves. Instead, the planning authority for each control area runs contingency analysis and voltage stability studies to ensure that the system has acceptable voltages in the operating state and following any unexpected events. Planning techniques vary across the country; in some regions voltage is a major concern and is studied extensively, while in other areas voltage problems rarely arise. System operators monitor real-time

voltages and use reactive power resources to correct voltage problems. Because reactive power needs vary widely by location and system conditions and since reactive power must be supplied locally, there could be numerous reactive power zones, each with different requirements for static and dynamic reserves.

2. Reactive Power Needs by Real Power Customers. A system's reactive power supply needs are also determined by the reactive power consumption by load. Reactive power consumption by load can differ by load type. For instance, some industrial market participants are large reactive power consumers. The use of reactive power by load is often identified through the load's power factor. In some areas, market participants with low power factors (and thus increasing the overall need for reactive power) are required to make additional payments (often referred to as power factor penalties) intended to compensate for the additional reactive power capability needed to serve the market participant. In other cases, such market participants are required to make additional investment in reactive power supply by the market participant. Identifying those entities responsible for the need for reactive power is an important aspect in evaluating reactive power pricing policy.[70] In this case, reactive power consumption by load should be measured to the extent that it is cost effective to spur efficient reactive power capacity investment and consumption decisions.

In many cases load response and load-side investment can reduce the need for reactive power capability in the system. For instance, peak real power loads due to high temperature are due primarily to increased air-conditioning needs. Many air-conditioning units consume reactive power, thereby increasing the reactive needs of the system concurrently. The joint consumption of real and reactive power by these market participants has a greater impact on the system than the consumption of real power by high power factor uses. Incentives to encourage efficient load-side participation to avoid additional investment in transmission and reactive power capability may be under-developed.

3. Reactive Power Consumption by Transmission. Reactive power also is consumed and produced by transmission equipment, but identifying the entity responsible for the reactive power need is more complex than measuring

[70] A basic economic principle, whether in cost allocation or market design, requires those causing costs to pay them; likewise, those incurring the costs should be compensated. The determination of efficient reactive power prices should reflect the marginal costs of reactive power service. Otherwise, there are subsidies and poor to bad incentives to behave efficiently and an increased probability of system failure.

consumption by load. Even if no real power customer consumes reactive power, the system requires supply for voltage support and to cover the reactive power consumption that occur within the transmission system. Reactive power needs for the system depend on the location of the real power supplies and real load. Due to significant reactive power consumption over heavily loaded transmission lines, generation resources that are located long distances from load create greater reactive power needs than resources located near loads. System operators will be the purchasers of the reactive power and will pass those costs to transmission customers.

4. Pricing Reactive Power to Transmission Customers. All transmission customers benefit from reliable operation of the system. System reliability – and thus a significant portion of the system's reactive power needs – is a public good. The pricing of a public good to its market participants is a difficult problem. Efficient pricing requires that market participants reveal their valuation of the public good, which in this case is system reliability. One simple rule is that those who do not benefit from a public good should not need to pay for it. This is true when the good is local in nature and only benefits a subgroup of market participants. Pricing should strive to charge those who benefit in rough proportion to the amount they benefit.

A difficult challenge is to determine which market participants increase the need for reactive power and which proportionally benefit. These market participants should be targeted to pay for the systemwide reactive power needs. Further, a significant portion of theses costs are associated with reactive power consumption within the system. One possible approach would be to identify the transmission customers responsible for the reactive power consumption that occur over transmission elements to maintain system reliability. When real power is supplied closer to load, less reactive power will be needed by the system. Distant power sources may require greater supplies of reactive power. Thus, under certain system conditions it may be appropriate that long distance transmission customers should be responsible for the costs of providing the additional reactive power needs of the system. Also, the real power load may be distant from the real power needs, so simply targeting load in the areas requiring reactive power may not be appropriate.

Real-Time Reactive Power Supply Issues

Reactive power capacity can be supplied through transmission as well as generation (including distributed generation) investment. The purchasers of reactive power are primarily limited to system operators who pass the costs through to transmission customers. Some real power customers may also procure reactive power resources to meet their own reactive power needs and/or obligations imposed by the system operator.

Generation and some transmission products may provide dynamic reactive power. Other traditional transmission products used to supply reactive power provide static reactive power. The primary costs in developing reactive power capacity are capital investment costs and form the basis for much of the long run marginal cost of reactive power. The variable costs associated with reactive power supply come from real power losses due to heating and opportunity costs for generators that result from forgone real power sales. The marginal operating cost of providing reactive power from within a generator's capability curve (D-curve) and from some transmission sources (such as capacitors) is near zero.

1. Real-Time Cost Structure. System planning has historically attempted to ensure that sufficient reactive power is available. As a result, there is a further likelihood that surplus reactive power capability will be available to the system at most times. This surplus reactive power capability is analogous to the surplus real power capability that is intended to maintain a reliability standard. Given the reactive power capability required to maintain reliability on a planning basis, it is not unlikely that the marginal cost of reactive power supply during most periods will be at or near zero. As a result, real-time market prices under competitive conditions at most times may be very low, and thus pure spot pricing may not be sufficient to cover all investments costs.

The investment cost structure for many transmission and generation-based reactive power solutions could be "lumpy." If an installed capacitor bank fully relieves a reactive power problem and were to set the reactive power price in a given location during most hours, the capacitor's full costs are

[71] The characteristics of the capacitor investment may make it a "lumpy" investment. The efficient investment size may eliminate the reactive power shortage in most periods.

unlikely to be recovered over time unless prices are sufficiently high when prices are not zero.[71] And if real-time reactive power prices are not compensatory, investment in capacity to provide reactive power is likely to be inadequate over the long term without a capacity requirement for reactive power capability. Whether marginal-cost pricing for reactive power is fully compensatory is an empirical question that depends on the knowledge of reactive power prices.

2. Real-Time Compensation Structure. In today's pricing environment, many generators are not paid for reactive power produced within certain operating bands and may be paid lost opportunity costs outside the bands. Interconnection requirements to provide capability for products that receive no compensation in the market provide little positive incentive to supply the desired product. Aside from the mandatory direction from the ISO or regulator there is no market incentive to encourage the supply of reactive power at any specific time. Such obligations on suppliers may discourage efficient maintenance or result in less than desired availability of supply. Under such a policy based on mandates, the supplier's goal is to minimize the cost of compliance. Minimizing the cost of compliance may differ from both minimizing the cost of production and maximizing efficient use of resources to meet market participant needs. Additionally, mandatory supply obligations relying on penalties for noncompliance require enforcement and information by the obligator. Finally, the costs associated with mandatory supply are not always apparent, thus making efficient decisions regarding competing supply less likely. There is little incentive to choose or identify a lower cost alternative.

3. Local Supply Market Power. Market power could exist in the supply of reactive power. Suppliers of reactive power are likely to have significant market power because reactive power is difficult to move over long distances due to the consumption of reactive power by the transmission lines. Power traveling over longer transmission lines at high loadings results in a higher percentage of reactive power losses to real power losses. As a result, fewer suppliers are ordinarily available to provide the reactive power needed at any individual location. Some type of regulation or market power mitigation may be needed to prevent reactive power prices from reflecting an exercise of market power if suppliers are given the opportunity to place supply bids.

4. Incentives to Increase Real Power Transfer Capability. The locational supply of reactive power can at times increase the available flow, or transfer capability, for real power between two points. Since reactive power and real power in combination congest the transmission system, increased reactive supply in the right locations can increase the transfer capability for real power. Existing pricing systems give no incentive to supply additional reactive power that may allow low priced real power to displace more expensive real power sources. This is particularly true if any increased supply of reactive power requires a reduction in real power output. Because the generator is generally only compensated for real power sales there is little incentive to provide additional reactive power even if it increases efficiency and lowers the total system costs.

5. Locational Siting Incentives. Reactive power pricing should encourage efficient locational siting of new generation. New generation siting decisions are often based on real power prices and incentives. New real-power generation that displaces existing real-power resources may place an increased burden on the system's need for reactive power due to its location on the network. Alternatively, new generation might choose locations that reduce system reactive power needs if the reactive power pricing incentives are apparent. Because reactive power losses in transmission lines are very high, generators near loads can supply reactive power with much lower losses than generators located long distances from loads. The system's reactive power needs and costs might be addressed through improved pricing mechanisms that encourage siting decisions that are consistent with the system's reliability needs.

Locational investment incentives from reactive power losses differ from the incentives from real power losses in existing regions with locational pricing. Suppliers in regions that have locational marginal pricing including marginal loss pricing inherently incorporate real power losses in their siting and dispatch decisions. Real power suppliers receive and real power market participants pay the marginal value of real energy at a given location. Under full locational pricing (with marginal loss pricing) a generator that increases the real-power losses on the system does in fact receive a negative signal of this cost through a lower locational price. Similarly, a generator that reduces the real-power losses will see the positive value.

6. Market Power by Reactive Purchasers. Market power by the system operator could also be a problem for some sellers of reactive power. Because reactive power needs are primarily identified and determined by the system operator, there may be an incentive to procure reactive power from resources that are affiliated with or provide a financial benefit to the system operator. These might include the discriminatory procurement of reactive power from generation resources and the development of rate-based transmission upgrades despite available alternatives. Additionally, the system operators may be able to exhibit monopsony power on reactive power suppliers and procure existing reactive power supplies at prices that do not signal or encourage needed investment.

7. Guaranteed Cost Recovery for Some Suppliers. Finally, market solutions may be undermined by the potential for cost-based investment directed by the system operators. If costly investments in reactive power capability come from the market without cost recovery guarantees, there may be limited assurances that the system operators might not subsequently purchase other sources of competing supply such as capacitors that are put into the transmission rate base. These risks discourage non-rate-based investment and bilateral contracting for needed resources.

Reactive Power Dispatch Example

The following simplified two-node model illustrates some of the potential benefits that come from efficiently dispatching reactive power above the required power factor constraints. In the example, using the full reactive capability of local generation units in a transmission constrained area can increase the transmission of real power into the constrained area lowering system costs by 20-30 percent. If the generator is not compensated in some manner, there is no incentive to provide the additional reactive power. In fact, the example shows a case in which there is less need for the local generator's real power when the local generator increases its reactive power output, illustrating the potential disincentive for generation resources within a transmission constrained area to provide useful reactive capability.

The example is solely for illustrative purposes and is not based on any actual dispatch example. The model shows the limitations of current pricing designs

that ignore the incentives to supply reactive power in the market. Additionally, the model illustrates the effect on costs of system operator decisions regarding voltage target levels. This example is meant to illustrate dispatch changes in steady-state situations, and does not take into consideration the implications of increasing reserves, such as adding capacitor banks. In reality, decisions to expand capacity by investing in other devices need to be considered.

The two-node model has one load, located at Bus A, with both real and reactive components. Real and reactive generation resources are located at both Bus A and Bus B. The real power capacity of Generator A is 500 MW. At maximum real output, Generator A is limited to a reactive power production of 150 Mvar by its physical constraints; however, at lower real output levels reactive power can be increased as defined by its D-curve constraints, i.e., 400 Mvar at 50 MW. In this example, the reactive power constraints are approximated by a linear function. The cost of real power production by Generator A is constant at $80 per MWh, and the cost of producing reactive power is $0 per Mvarh, which ignores the small cost of losses in the generator. The real power load at Bus A is 1,000 MW and reactive power load is 500 Mvar.

The production of real and reactive power by Generator B, located at Bus B, is assumed to be unconstrained. The cost of real power production by Generator B is constant at $10 per MWh, and the cost of reactive power production is $0 per Mvarh. A transmission line with a thermal capacity of 1,000 MVA connects Bus A and Bus B. Other line parameters are shown in the figures below. In the figures, the one transmission line is represented by two flows: The larger, green arrows on the upper line represent the direction and magnitude of real power flow in MW; the smaller, blue arrows on the lower line represent the direction and magnitude of reactive power flow in Mvar.

In Case 1 the system operator dispatches the system incorporating the limiting reactive power supply constraint of 150 Mvar from Generator A using PowerWorld software. PowerWorld, the simulation software used to generate these examples, uses real power controls to obtain an optimal solution. PowerWorld does not currently co-optimize reactive and real

power, and it does not consider a cost for producing reactive power. This is true in other commercial power flow software packages as well; the reason is that the reactive power optimization is nonconvex, and requires more complicated optimization tools. The marginal cost of reactive power shown in the examples is calculated from the change in real power losses from increasing the reactive power demand; it does not include the higher opportunity cost of backing off real power production subject to the D-curve constraint.

By restricting reactive power production by Generator A to 150 Mvar or less, the least cost system dispatch cost is $20,647 per hour. Generator A produces 144.9 MW of real power and its full 150 Mvar of reactive power. Generator B produces 905.8 MW and 423.8 Mvar. A total of 1,050.7 MW is produced, of which 50.7 MW, or 4.8 percent of total real power, is consumed as losses over the transmission line. Generator B produces 573.8 Mvar of reactive power, of which 73.78 Mvar, or 12.9 percent, is consumed as losses over the transmission line. The transmission line is operating at full capacity, carrying 1,000 MVA from Bus B. Although the target per-unit voltage levels at buses A and B are both 1 per unit (pu), given the other constraints in the model, the PowerWorld software calculates the actual voltages to be 0.91 pu and 1.00 pu for Bus A and Bus B, respectively. The model was unable to achieve the target voltage level of 1.0 pu at Bus A and still respect the transmission line limit and reactive power requirement for Generator A.

Clearly, Generator B can supply the real power to the system at a lower production cost than A, and we would prefer to dispatch more of its capacity. However, because the transmission line is congested no additional real or reactive power can flow from B to A. More specifically, the transmission line is loaded at 1,000 MVA at Bus B, meaning the constraint is binding at that point and no more power can be injected. At Bus A, the load on the transmission line is 935 MVA. Increasing reactive power production by Generator A will reduce the need to use Generator B to supply reactive power to Load A, and decrease the amount of reactive power necessary at B on the transmission line. Reducing reactive power flow on the transmission line allows increased transmission of cheaper real power from Generator B to Load A.
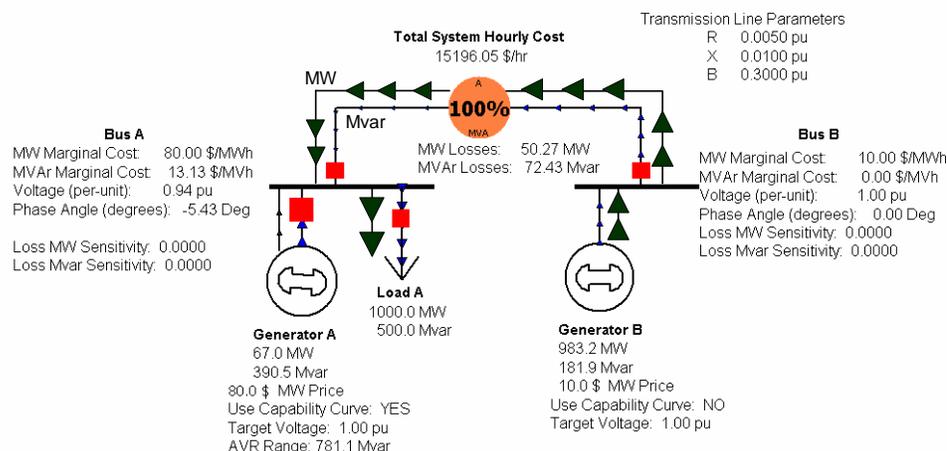
Case 1
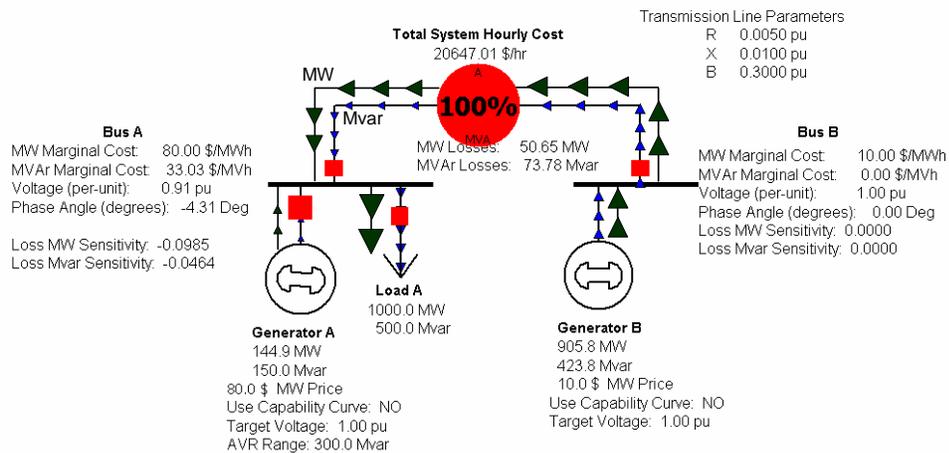
In an environment where there is no reactive power pricing, Generator A has no incentive to increase its reactive power supply because doing so will decrease the amount of real power it will get paid for. In fact, if Generator A were operating at a point on the limit of its D-curve, increasing reactive power output would actually reduce the generator's revenue because it would sell less real power, unless it was paid for the supply of reactive power. Therefore, higher total system costs can occur than if reactive power production were compensated.

If the ISO has the flexibility to dispatch Generator A at any feasible point within it D-curve or if generators were given location-based incentives for producing reactive power, a more cost-effective dispatch is available, as shown in Case 2. System costs for this case drop as Generator A increases its production of reactive power, reducing the need for transporting it from Generator B, and frees up transmission line capacity for increased real power flow from Generator B to Load A. Generator A increases its reactive power production to 390.5 Mvar, and reduces it real power production to 67 MW, an operating point which lies on its D-curve, approximated as a linear function in the software and illustrated below in Figure 1. Generator B

increases its real power output to 983.2 MW and decreases its reactive power to 181.9 Mvar. Because it is now providing more real power than Generator B, and because its production costs are cheaper than Generator B, the system cost is reduced by $4,551/h, or 22 percent, to $15,196/hr. The per-unit voltage level at Bus A increases to 0.94 pu, which is still below, but closer to, the target voltage of 1.00 pu. This is because, again, there are other system constraints that must be enforced. Losses over the line decrease for both real and reactive power; the line consumes 50.3 MW and 72.4 Mvar.

Case 2

Transmission Line Parameters
R   0.0050 pu
X   0.0100 pu
B   0.3000 pu

Total System Hourly Cost
15196.05 $/hr

MW

Mvar

100%
MVA

MW Losses: 50.27 MW
MVAr Losses: 72.43 Mvar

Bus A
MW Marginal Cost: 80.00 $/MWh
MVAr Marginal Cost: 13.13 $/MVh
Voltage (per-unit):   0.94 pu
Phase Angle (degrees):   -5.43 Deg

Loss MW Sensitivity: 0.0000
Loss Mvar Sensitivity: 0.0000

Bus B
MW Marginal Cost: 10.00 $/MWh
MVAr Marginal Cost: 0.00 $/MVh
Voltage (per-unit):   1.00 pu
Phase Angle (degrees):   0.00 Deg
Loss MW Sensitivity: 0.0000
Loss Mvar Sensitivity: 0.0000

Generator A
67.0 MW
390.5 Mvar
80.0 $ MW Price
Use Capability Curve: YES
Target Voltage: 1.00 pu
AVR Range: 781.1 Mvar

Load A
1000.0 MW
500.0 Mvar

Generator B
983.2 MW
181.9 Mvar
10.0 $ MW Price
Use Capability Curve: NO
Target Voltage: 1.00 pu

Source: Derived from *PowerWorld*

It is interesting to note what happens to the revenue of Generator A. Going from Case 1 to Case 2, Generator A produces more reactive power to allow more real power production from Generator B, thus reducing system costs. At the same time, Generator A is forced to back down its production of real power by 67 MW not only because it is being displaced by Generator B, but also because it is forced to comply with its operating constraints. Lost revenue as a result of this decreased real power output is (67 MW) x ($80/MWh) = $5,360/hr, in this example. If Generator A is not compensated for reactive power production, there is no incentive for it to back down real power.

Figure 1. **Generator A D-Curve and Operating Points, Case 1 and 2**
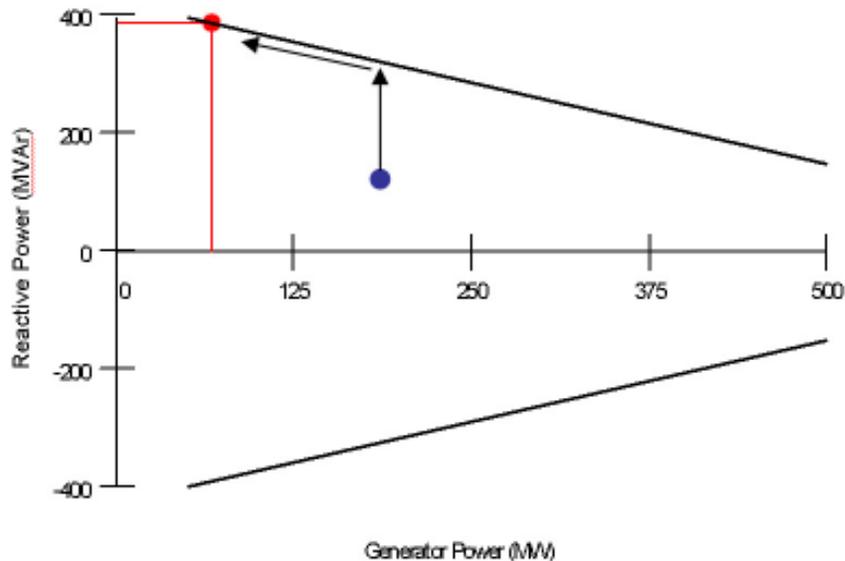
Source: FERC Staff

The marginal price of reactive power is shown to be $13.13 per Mvarh. This is the increase in system cost as a result of increasing demand for reactive power by 1 Mvar at Bus A. If demand for reactive power is actually increased to 501 Mvar, the following changes take place: Generator B produces 0.2 MW more of real power in order to free-up capacity on the transmission line. Generator A produces 0.3 MW less of real power – less is needed as a result of the increased real power production at Bus B – but injects more reactive power to supply the increased load at Bus B. The new real power dispatch causes a change in system cost; the increase of 0.2 MW at Generator A costs $16, and the decrease of 0.3 MW at Generator B reduces cost by $3. The total change in system cost is $13 (within rounding), the marginal cost of reactive power at Bus A .

Why doesn't Generator A produce its full 400 Mvar? Presumably, this would further increase line capacity available for cheap real power from Generator B and reduce the system cost further. The reason for this is the transmission

line constraint. If Generator A is forced to produce 400 Mvar, its real power production falls to 50 MW, and 1002.1 MW is required from Generator B since losses or consumption in transmission are about 50 MW. However, some reactive power is still needed from Generator B, and in order to fulfill both real and reactive load at Bus A the transmission line will become overloaded. The only way to relieve the congestion, and still respect the physical limits of the generator, is to increase real power and decrease reactive power production at Generator A, moving along the D-curve until the constraint is alleviated. Incidentally, this is the same reasoning behind the system response to increased reactive power demand at Bus A, discussed above. The increased demand is not supplied by Generator A because that would require a reduction in real power, requiring in turn an increase of real flow from Bus B to Bus A, which would overload the transmission line.

Voltage targets defined by the system operator have an impact on system dispatch and costs as well. Case 3 allows the target voltage level to rise to 1.05 pu at Bus B and, as a result of system response, reduces costs relative to Case 2 by $581, an additional 4 percent, to $14,615. An additional benefit of loosening the voltage requirement at Bus B is that the voltage level at bus A rises to .99 pu. The system operator can effectively place a value on system reliability by choosing at what cost it is willing to adjust its desired voltage levels.

Case 3
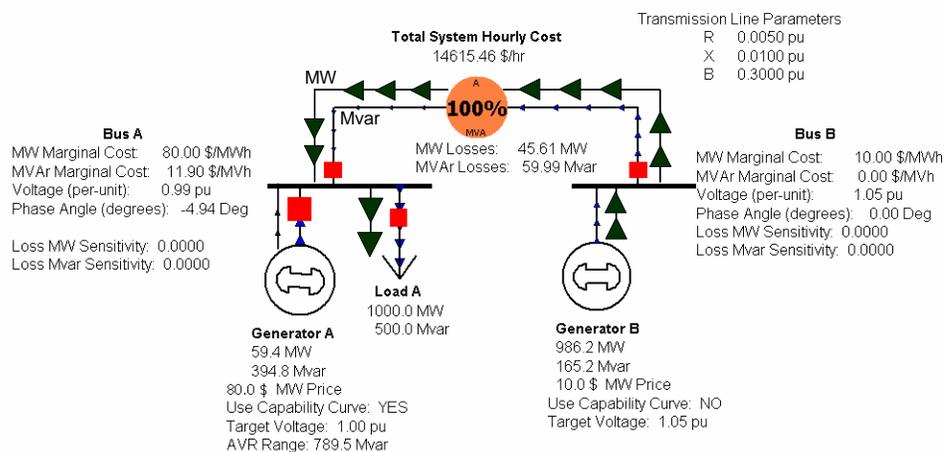
Source: Derived from *PowerWorld*

Pricing and Procurement Options for Reactive Power

After the reliability needs of the system have been determined, the goal of reactive power pricing and procurement should be to encourage two efficient outcomes. First, it should encourage efficient and reliable investment in the infrastructure needed to maintain the reliability of the transmission system. Second, it should provide incentives for the reliable and efficient production and consumption of reactive power from the existing available infrastructure, taking into account the opportunity costs of the provision of competing uses of the available resources (such as real power and operating reserves). Additionally, it is important that any pricing system allows the system operator real-time control over reactive power resources. While pricing rules should complement the reliability needs of the system, in some situations, the system operator may need to adjust reactive power resources, applying out of market dispatch instructions during system emergencies.

In both independent system operator (ISO) and non-ISO markets, reactive power capability is paid on a cost-of-service basis to transmission suppliers. Transmission elements that supply reactive power generally have their costs rolled into transmission charges or into the regulated retail rate structure. Generation suppliers are paid for reactive power through reliability-must-run (RMR) contracts, cost-based payments or not at all. In some ISO and non-ISO markets, generators have reactive power obligations based on their interconnection and/or participating generator agreements with the system operator. These generators have reactive power obligations and are required to supply reactive power with out additional compensation.

To maintain the reliability of the system, real-time reactive power supply is needed as well as reactive power capacity to serve as reserves. We review three different approaches to pricing the supply of reactive power capability and real-time reactive power supply. To procure needed reserves and supply of reactive power, the pricing approaches can be applied comparably for transmission, generation and load.

1. Cost-of-service payments
   a. Uniformly to all suppliers
   b. To those suppliers that fulfill an identified system need
2. Prices from a forward auction process
3. No payment to generation or load sources, payments to transmission sources

To price the real-time supply of reactive power sources, we review four possible approaches.

1. No payment for supply within a required bandwidth or capability level
2. Payment of lost opportunity costs (such as forgone real-power sales)
3. Locationally specific market clearing prices based on either on bids or opportunity costs
4. Fixed price schedule developed in advance
   a. Uniform price
   b. Unit-specific basis

General Pricing Principles and Regulatory Intervention

1. Efficient Investment and Regulatory Intervention. The decision to make a private investment, or for the government to make or force an investment or to otherwise intervene in the market, is typically based on a cost-benefit analysis. For private firms, the cost-benefit analysis becomes an expected profitability and risk analysis. In a private enterprise economy, government intervention should come only in anticipation of or after a significant market failure. A market failure is said to occur when the market outcomes deviate from efficient outcomes.

When a market cannot be efficient without government regulation, it is considered a market failure. Regulatory or other government interventions offer potential solutions to market failures, which can result from the effects of externalities, public goods, market power and information imperfections. Reactive power markets today are the product of the regulatory framework based on the perceived economies of scale and scope of the electric utility industry.

Externalities occur when the actions of market participants are not priced into the market. If left to itself, the market will supply less of a public good than desirable and more of a product with negative externalities than desirable. Examples of public goods are roads, local police, clean air, national security and electric reliability.

Market power can also lead to inefficient market outcomes. Market power occurs when market participants can influence the price. Market power occurs naturally if there are economies of scale or scope. Market power is exercised by sellers when less of a good is produced to drive up the market price. Market power is exercised by buyers when less of a good is purchased to drive down the market price. Market power also is created when the government awards a monopoly franchise that legally prohibits competition as in the case of system operators and utilities. In many markets, reactive power is supplied, in effect, by franchise monopolies.

Information asymmetries can also lead to market failure. Information asymmetries occur when all market participants do not have the same information. When the access to market information is controlled by a market participant, inefficient outcomes can arise. Information asymmetries are corrected by ISOs via the information it publishes on public Web sites. For a vertically integrated utility, affiliate rules are a weak "second best" approach to avoiding information asymmetries. Market participants need good information to make efficient decisions. Information concerning reactive power is typically either not calculated or not disseminated widely. There is very little public information regarding the specific needs for and deployment of reactive power.

2. Efficient Regulation Criteria. When significant market failures occur, the government or coalitions of market participants often intervene with additional rules, market designs or investments to move the market back to more efficient outcomes. In futures and stock markets, the exchanges make rules overseen by the U.S. Securities and Exchange Commission (SEC) and the Commodities Futures and Trading Commission (CFTC). In wholesale electricity markets, the FERC both makes the rules and oversees the market rules.

Public investment should be made at the lowest efficient cost. Procurement auctions and competitive contracts are used to procure the needs at the lowest cost. Auctions are prominent in highway construction and defense procurement. Regulated franchised monopolies are also used to make investments. Competitive hiring is used for personnel needs.

Public investment must be paid for. Public goods can have locational dimensions. One pricing principle is that those who benefit pay in proportion to the benefit. For example, one difference between local police and national defense is who pays. Local police and other first responders are usually paid for by the local community, but national defense is paid for by the entire country from general federal tax revenues. It is also common in the United States to have multistate regional organizations for activities such as water or transportation management. For electricity, ISOs and regional transmission organizations (RTOs) fill that niche between purely local or state organizations and the federal government.

Generally, private firms have little ability or incentive to correct market failures. Traditionally, the market power of franchised monopolies was mitigated by cost-of-service pricing. When formerly franchised monopolies are exposed to competition, cost-of-service pricing often breaks down revealing higher prices than the competition creates, which in turn gives rise to stranded costs.

For externalities and public goods, the market design should result in prices through which those benefiting are paying for the public good and those causing externalities pay for the damage caused. Pollution externalities are often priced by taxes on pollutants (also known as Pigouvian taxes) or in cap-and-trade markets, e.g., SO_2 and NO_X, where the government decides the level of pollution and monitors for compliance. In these markets, market participants are allowed to create or purchase and store pollution credits for future use. When roads or other transportation systems become congested, they lose their public good quality.

When market failures are addressed through regulatory market rules and requirements - especially with minimal intervention - residual competition can provide an opportunity for efficient market outcomes.

3. Market Rules and Regulation to Simulate Efficient Outcomes. In the absence of externalities, competitive markets result in an efficient allocation of resources. Perfectly competitive markets are characterized by a large number of small buyers and sellers. None of the individual actions by market participants can impact the price. All market participants have perfect information in competitive markets as well as no barriers to entry and exit. The prices that result from these markets are determined at the level at which supply meets demand, and move instantaneously to maintain this equilibrium balance.

In regulating reactive power markets, an important question is whether reactive power prices should include the characteristics of prices in competitive markets, which encourage efficient outcomes. These characteristics arise naturally in competitive markets because of market pressures, without imposition from government regulation. In markets that are not structurally competitive, market designs such as auctions are used to obtain desired outcomes. In electricity markets, two desired outcomes are efficiency and reliability.

There are three key characteristics of competitive markets:
First, prices in competitive markets tend to reflect sellers' marginal costs. Such prices send desirable signals to market participants. This characteristic helps ensure that the efficient amount of output is produced and consumed. That is, output is produced only when the product's value to market participants at least matches the cost of producing the incremental output. During shortage periods (also identified as scarcity situations that may include unplanned outages), competitive prices will be determined by the marginal customers' value of consumption, meaning that competitive prices are set by the demand curve when the supply runs low. At these times, prices will exceed the marginal cost of production, but reflect the marginal value on the load side.

By contrast, prices in noncompetitive markets can exceed the marginal cost during nonscarcity conditions. The higher noncompetitive prices reduce demand that could have been met at a cost less than the value to consumers. In markets without significant market power, competition keeps prices near marginal cost, because if prices rise above the marginal cost of the most

expensive supplier needed, sellers with spare capacity below the price will offer their spare output to the market and thereby reduce the price.

Second, in a competitive market, all sellers (at any given time and place) receive the same price for the same product. This feature ensures that the demand is met by the lowest-cost producers. Any seller whose costs exceed the price would face pressure to exit the market. Competition keeps prices the same to all market participants. No seller would willingly sell below the market-clearing price and no buyer would willingly pay more than the market-clearing price. However, where sellers face economies of scale or scope, price discrimination among buyers may be necessary in order to allow efficient sellers to recover their costs and give buyers the lowest overall costs.

Finally, long-term contract prices tend to reflect expected future real time market prices. If contract prices were significantly higher than expected real time prices, market participants would refuse to sign contracts because they would expect lower costs in the real time market. Conversely, if contract prices were lower than expected real time prices, load-serving entities (LSEs) would abandon real time purchases in favor of the lower contract price. Decisions to enter into long-term contracts also include the risk tolerance of buyers and sellers.

There are at least two ways to compensate reactive power providers. One way is to pay them in advance for their reactive power capability (capacity). This is the typical way that most providers are compensated currently. The pricing options for the short-run supply of reactive capability are discussed below in this chapter. To complement or supplement compensation for reactive power supply capacity there may be useful reasons to price real-time reactive power supply particularly for generation resources that can provide reactive power. The pricing options for the short-run supply of reactive power are discussed following the capacity options in this chapter. While it is possible to rely on only one of these ways, the methods are not mutually exclusive, and indeed there may be benefits to using both methods.

Options for Pricing Reactive Power Capacity

Once the reliability coordinator or planning authority has identified the reliability need, there are several approaches to pricing the supply of reactive power capacity that meets this need. The pricing alternatives for reactive power supply may be applied locationally to all sources of reactive power, such as generation, distributed generation, capacitors and FACTS. The pricing rules potentially may be applied differently to differing supply resources based on their operating and supply characteristics. Further, differing options may be used to compensate differing capacity supply types. For instance, static and dynamic reactive power capacity may be priced differently.

There are additional options regarding the time frame in which reactive power capacity should be procured. One approach to procurement would incorporate the reactive power planning process and procure needed capacity on a long-term basis based on forward planning criteria. Another approach could shorten the time frame and allow shorter term procurement periods such as an annual procurement. Differing approaches may also be taken with regard to static versus dynamic reactive power supplies.

A reactive capacity requirement framework for reactive power supply that parallels existing ISO (real power) capacity markets may be useful in developing adequate reactive power capacity. The current ISO (real power) capacity requirements exist to ensure that adequate generation resources are available in the system to maintain a desired level of reliability. The capacity product is intended, in part, to provide a market mechanism for sufficient investment in generation resources that will be used in a limited number of hours in a given year, but are needed for reliability on a planning basis. In the absence of the capacity product, revenues may be insufficient for fixed cost recovery (absent the exercise of market power). This is not generally viewed as a desirable market feature and does not ensure a desirable level of reliability. Dynamic reactive power capacity serves a similar purpose. Investments in dynamic reactive power capacity serve a valuable reliability role in the system operation. Yet, the system operator may rarely need to dispatch the dynamic reactive power resource, thus the capacity requirement

framework can provide a transparent mechanism to ensure that adequate reactive capability is available to maintain system reliability.

1. Cost-Based Capacity Payment. A cost-of-service compensation package can be developed to compensate suppliers for available reactive power capacity. Reactive power suppliers would be obligated to make their reactive power capacity available to the system operator in exchange for the payment.

There are two primary approaches in deciding which suppliers are eligible for the cost-of-service capacity payment. First, all suppliers of reactive power capacity could be eligible to receive payment from the system operator. Second, the system operator could pay only those suppliers that it identifies as providing needed reactive power capability to the system.

The first option, a blanket cost-of-service payment for all available reactive power capacity, may not result in reactive power capacity investments being targeted to areas that need it. Because the compensation for reactive power capacity is not closely related to the need for the capacity, there may be overinvestment in areas that do not require additional reactive power and underinvestment in areas that are in need. However, this approach avoids questions regarding inequitable treatment among market suppliers particularly generators. Some potential reactive power suppliers argue that decisions of need by system operators are not made in a fair, least-cost and nondiscriminatory manner.

The second, cost-based approach would be to have the system operator procure all reactive power capacity needs through cost-of-service payments. This approach would require a clear needs assessment. This approach gives the system operator the ability to target its needs and avoid the costs of procuring resources above the system needs. The cost-of-service arrangements could be made on an annual basis, as is done in some areas through RMR contracts to supply reactive power. Alternatively, the payment structure could be over the life of the asset as is traditionally done for transmission source of reactive power. However, this approach by the system operator may have the ability to give preferential access to these cost-based payments to select suppliers. In this case mechanisms to incent efficient and

non-discriminatory procurement are needed. It is important to allow all solutions to compete to provide the least cost solution to the identified need.

2. Explicit Payment for Reactive Power Capacity through Systemwide Forward Procurement. The system operator could hold an auction for reactive power capacity in which suppliers would be compensated for a commitment to make reactive power capacity available to the system. This payment would be for a physical call option on the capacity, and the actual supply would either be without further compensation or among the options outlined later in this chapter. This approach allows competition among generation and transmission elements to supply reactive power needs.

Requirements would likely be set locally, based on the needs determined by the system operator. This would allow prices to reflect the locational value of reactive power capacity and avoid paying for excess capacity in areas that do not need it. The length of the procurement term may differ based on an evaluation of the market characteristics and competitive alternatives. For instance, if efficient alternatives can compete to fulfill the need with relatively low capital costs or with mobile infrastructure (such as mobile SVCs) a shorter term procurement period may be advantageous. However, if significant barriers to entry exist for entry a longer term procurement period may be most effective. In instances where locational market power exists, cost based offers could be required to prevent the exercise of market power.

The forward procurement of reactive capability could be part of an overall forward resource adequacy procurement process. PJM is in the process of developing a proposal that would procure capacity obligations in advance through a forward auction. The proposal currently includes operational constraints that must be met as part of the auction's solution. Suppliers would be paid a premium for providing operational flexibility to the system if the auction determines that a premium payment is needed. Reactive power capacity needs could also be built into this type of framework to ensure adequate procurement of reactive power capability in advance. Prices would be low or even zero if there existed excess supplies of the operational capability, and would rise when the capability was in shorter supply. The forward procurement would allow the opportunity for existing participants

to incorporate incremental future investment opportunities into their bids and allow new investment to compete as well.

3. Pay Nothing to Generators; Pay Cost-of-Service/Forward Procurement for Transmission Solutions. Finally, we could rely on regulatory mandates on all generators to supply reactive power without further compensation and rely solely on cost-of-service transmission procurement by the system operator. Under this option there would be an obligation by generation resources to supply reactive power through a generation interconnection agreement or some other capacity obligation. Transmission solutions to meet reactive power needs could either be procured through cost of service investment or forward market based procurement.

For systems that have installed capacity (ICAP) requirements, the obligation to hold reactive power capability or to supply reactive power can be part of the generators' obligation as a capacity supplier. No supplemental payment for reactive capacity would be made. This mechanism will result in investment to jointly supply the real and reactive capacity needs. Generation, transmission and load can participate to meet these requirements. The costs of this investment will be passed through via capacity prices. Locational requirements for real and reactive power may not be coincident, however. Reactive power tends to be more location specific and the locational capacity needs for real power will not necessarily ensure that locational needs for reactive power are met. Therefore, capacity needs for real and reactive power may be most efficiently procured separately.

Ultimately, under this option, the new generation may be designed with only minimum reactive power capability and will result in a need to over invest in transmission assets even when generation based solutions would be less costly. Further, generation resources that could provide valuable reactive capability to a local area will have no incentive to incorporate this value into its locational investment decision and may choose to locate in a less costly area that has lower reactive need.

Under each of the three options, penalty mechanisms for nonperformance will need to exist and will need to be adequately enforceable. Reactive power suppliers would be expected to supply reactive power at the instruction

of the system operator for the benefit of the system. While nearly all market participants are adversely impacted by a system collapse, the short term incentives to supply real power (which receives compensation) rather than reactive power could lead to inadequate reactive power supply in times in which there is an opportunity cost to reactive power supply. Additionally, lack of compensation real-time mechanisms may lead to reduced maintenance incentives that adversely affect a unit's ability to supply reactive power when it is needed most.

Real-Time Pricing of Reactive Power

There are several approaches to pricing the short-run supply of reactive power in ISO markets. These pricing options may replace or complement the revenues from supply of reactive power capacity described in section C. The pricing alternatives for reactive power supply may be applied locationally to all sources of reactive power, including generation, distributed generation, capacitors, FACTS and others.

1. Background. Currently, very little reactive power procured in real-time receives any payment. Rather, transmission providers and system operators procure reactive power from a combination of owned assets and generators that are required to provide reactive power as a condition of their interconnection to a grid. To the extent that suppliers are compensated for reactive power in real-time, it occurs in some ISOs that pay generators for their individual lost opportunity costs when supplying reactive power. Real-time prices and compensation for reactive power should reflect real-time costs incurred with the actual supply of and opportunity costs of supplying needed reactive power, not market power.

Pricing reactive power supply in real-time is generally more complex than paying for capacity. Approaches to reactive power pricing must take into account the benefits and the costs of each method. Simple pricing rules, such as not paying for real-time reactive power supply are the least complex to implement, but may not lead to efficient reactive power investment decisions and dispatch. However, more complex approaches may introduce technical challenges and bring with it the need for additional market power mitigation rules to achieve the potential efficiency gains. Additionally, more

complex real-time solutions will require additional software development, well defined reactive power standards, and significant policy discussion before the possibility of implementation.

Benefits of Spot Compensation. There is often more than one source for obtaining reactive power at a given place and time, and some market participants can adjust their consumption of reactive power. Establishing a real-time reactive power price reflecting the market's locational marginal cost could encourage efficient decisions by market participants. It would encourage the lowest-cost suppliers to provide the reactive power. It would also encourage consumers of reactive power to evaluate their net consumption of reactive power, consuming it when the price is worth the value and reducing their consumption when the price is higher than the value.[72]

Reactive power equipment, especially static equipment such as capacitors, cannot switch instantaneously. Frequent switching of such equipment increases wear and tear and reduces the lifetime of the equipment. Real-time pricing systems for reactive power could need to take this into account, with factors similar to minimum up and down times used in generator commitment for ISO power markets.

Marginal Cost Pricing in Real-time. Marginal-cost pricing may not compensate suppliers for the full cost of reactive power (including capital costs) over the long run. In fact, the prices of real-time reactive power supply during most times may be close to zero. To supplement real-time revenues a payment such as those detailed above would likely still be needed to ensure adequate investment.

The marginal cost of providing reactive power from within a generator's capability curve (D-curve) is near zero. However, the suppliers' capital costs may be significant. Similarly, installed transmission resources (such as capacitors) have minimal costs beyond the initial capital expenditures. Under both cases real-time prices that reflected the operating costs would be at or near zero. The suppliers' full costs are unlikely to be recovered over time unless the prices were sufficiently high at times when prices were positive.[73] If reactive power prices are not compensatory in total, investment

[72] Practically speaking, load that consumes measurable reactive power would typically correct this problem with the installation of capacitors. Once installed, these units would provide the consumer with its reactive power needs. The system operator could turn off such devices if lower voltage levels were desired.

[73] The characteristics of the capacitor investment may make it a lumpy investment. The efficient investment size may eliminate the reactive power shortage in most periods.

in capacity to provide reactive power is likely to be inadequate over the long term. An available approach is to use a real-time procurement and pricing to complement a capacity based procurement for reactive power. The capacity market would in this case be the primary vehicle for fixed cost recovery, while the spot revenues would cover any short-term operating costs and potentially provide contributions to fixed costs.

Market Power, Bidding Constraints. Competitive markets are composed of buyers and sellers that are unable to control prices. This assumption does not necessarily hold in the supply of reactive power. Suppliers of reactive power may have significant market power at times because reactive power is difficult to move over long distances during heavy line loading due to the consumption of reactive power by the transmission lines. Additionally, at high loadings, power traveling over transmission lines results in greater relative reactive power losses than relative real power losses, further limiting the ability to use distant resources to supply reactive power. As a result, fewer suppliers are ordinarily available to provide the reactive power needed at any individual location, particularly in peak loading periods. However, the narrow geographic definition of a reactive power market may be offset by the potential additional suppliers. For instance, generation, transmission and load can all install devices that produce and consume reactive power. Nevertheless, regulation or market power mitigation may be needed to prevent reactive power prices from reflecting an exercise of market power.

Forward Procurement and Hedging. Many products and services - including real power - are bought and sold in both real-time and forward contract markets. Forward contract markets allow market participants to lock in trades in advance and hedge risk; real-time markets allow participants to adjust their forward positions as market conditions change, making it less risky to enter into forward contracts. Importantly, real-time markets for real power help facilitate reliably meeting demand with the lowest-cost resources that are available in real time. Resources committed to supply under contract may be more expensive than other resources available in real time. The real-time market allows expensive contract resources to transfer their responsibilities to lower-cost resources, allowing both resources to benefit. Also, open real-time markets operated by ISOs provide transparent real-time prices that help provide a point of reference in negotiating contract

prices. Real-time markets could potentially provide similar benefits for procuring reactive power until the forward markets stabilize.

To mitigate suppliers' reactive market power, mitigation mechanisms could be in place to ensure that suppliers' bids reflected their marginal costs (including opportunity costs). For instance, supply offers within a generator's capability curve could be restricted to a level near zero because no significant opportunity costs exist in the supply of reactive power. Bids for reactive power outside this range could be restricted to opportunity costs based on the physical attributes of the unit's capability curve (for more detail see appendices B and D). Under this approach cost of service transmission elements would also offer reactive capability at incremental costs (for more detail see appendices C and D). The result would be prices that reflect the marginal cost of delivering real and reactive power to each location.

Because the system operator is the primary procurer of reactive power, it is likely to have monopsony power and the ability to affect the price. Additionally, the system operator may also be a competing market participant in the generation or transmission reactive power supply resources. However, much of the real-time needs should be an automated feature based on the system operator's dispatch software and, thus, not likely to be subject to manipulation by the system operator. Auditing of the system inputs and parameters may, however, be necessary in situations where the operator is a market participant. Clear, transparent and nondiscriminatory procurement rules would be needed to overcome this conflict.

Transaction, Hardware and Software System Costs. The transaction and investment costs associated with the development of a locational real-time pricing differ by option. For instance, it is possible that the transaction costs associated with the development of a locational real-time market for reactive power supply that parallels existing real-time energy markets may outweigh the potential benefits. It may be argued that the associated software and hardware costs for implementation, together with the software and hardware costs of the mitigation procedures and the staff costs of market monitoring, outweigh the efficiency gains. Whether this is or is not true is an open question and worthy of further investigation as reactive power policies are developed.

2. Payment Options For Real-Time Supply Obligation. There are several approaches to pricing the short-run supply of reactive power. These pricing options may replace or complement the revenues from supply of reactive power capacity described above. The pricing alternatives for reactive power supply may be applied locationally to all sources of reactive power, including generation, distributed generation, capacitors, FACTS and others.

No Payment for Production within Bandwidth/Physical Rating. One approach is to mandate that reactive power be supplied within a fixed range at no additional cost. This generally corresponds with the existing practices where reactive power capability may be paid for, but real-time reactive power supply is not compensated.

System operators would have the ability to dispatch running generation units to supply reactive power within the bandwidth without further compensation. Revenue to support the investment would come from the pricing of reactive power capacity or expected infra-marginal energy sales that contribute to a supplier's fixed cost (in the case of generation sources).

For transmission elements such as capacitors and FACTS devices, the required supply bandwidth could simply correspond with the physical rating of the element. The system operator would have control over the elements and use them to meet the system voltage needs. The transmission facilities would receive no additional compensation based on their use. Again, as for generation resources, the capital cost recovery would be generated from the pricing of reactive power capacity.

For generation, the bandwidth requirement may be based on the capacity sold in advance or based on an administratively determined fixed range measured at the high side of the step up transformer. The fixed range could be based on a universal generator power factor or a fixed percentage of the unit's maximum output. If this fixed range is within the generator's nameplate power factor, the incremental cost to the generator will generally be limited to losses as there will be little or no forgone real energy output. Under this approach, a generator with a nameplate power factor lower than the requirement may incur significant lost opportunity costs due to reductions of real power output in order to meet its obligation to supply reactive power.

This approach would allow a generator to evaluate its investment in the infrastructure needs to supply reactive power. For instance, a supplier may choose an oversized turbine to maximize the real power output of the generator at a unity power factor. However, in operation this configuration may expose the supplier to higher opportunity costs to supply reactive power as it may have to back down real power supply to meet its reactive power supply obligation. In this case, it will not be in the generator's financial interest to follow dispatch instructions absent an ex-post penalty structure and may not be the most economical way of achieving the desired result. Further, backing down real power output in peak periods may be problematic.

Investment to increase reactive power capability by generation resources would be determined jointly by the payment structure for reactive power capacity and the expected trade-offs between increased capital expenditures to relax the D-curve constraints and lost energy sales from required reactive power supply.

This pricing approach would also be consistent with a contract with RMR resources[74] that are paid a cost-of-service rate for the supply of reactive power capacity and receive no specific revenues associated with the quantity of reactive power supplied.

While the system operator could procure reactive power from suppliers at no charge within the band, opportunity cost payments for reactive power would be needed at a minimum for supplies outside of the band.

Overall, this approach requires little development of additional software and minimal settlement costs because most participants will not receive payment. Real-time market power concerns are also not of significance, however, the potential for physical withholding remains. Lack of payment could result in reduced maintenance incentives and lead to inefficient investment decisions.

Opportunity Cost Payments. A second approach to pricing reactive power would pay lost opportunity cost for supplying reactive power. For transmission elements this price is at or near zero and as a result they would

[74] Reliability-must-run (RMR) units have traditionally been units that do not receive sufficient revenues through the markets to remain profitable but are needed to maintain the reliability of the system. Often these units have market power, but are prevented from the exercise of market power through mitigation rules. Inadequate market pricing mechanisms can prevent adequate revenues from the market for these specific units. RMR contracts between the system operator and the RMR generator ensure adequate revenues and cost recovery, but fail to send a signal to the market in cases where new infrastructure is needed.

receive little or no payment. Generation resources may, however, experience real-time opportunity costs in supplying reactive power in real time. Most ISOs have such payment mechanisms in their tariff. To date, this tool has not been widely used in those areas that have such mechanisms.

Any supply of reactive power that resulted in reduced real output would be compensated based on profits forgone from the real power sale lost based on the D-curve constraint. This approach might result in differing payments to suppliers offering the same quality of reactive power because payment would be based on each supplier's own unique lost opportunity cost of forgone energy sales. Such an approach will not encourage investment in the infrastructure needed by generators to supply reactive power because there may be no contribution to fixed costs from reactive power sales. Investment would likely only come as a result of interconnection obligations or through payments for reactive power capacity. In fact, an existing unit may have an incentive to increase the turbine size to increase the capacity of real power output at the expense of the unit's power factor. If there is no compensation or obligation to provide reactive capability then there is no incentive for the generation owner to provide the reactive power service that avoids any opportunity cost of real power.

Market Clearing Prices. Another approach would be to pay all suppliers the applicable market clearing price analogous to locational payments for real power. This approach could be applied to both generation and transmission sources of reactive power. Revenue collected from cost-of-service reactive power supplies could be credited back to the applicable customers.

In this case, suppliers will have the incentive to voluntarily invest in reactive power capability because the market clearing mechanism could provide some fixed cost recovery for investment in reactive power capability. This market design could also accommodate the demand, or load, side. Because all reactive power would be priced reactive power, potentially large revenue transfers are possible as suppliers receive payment for all reactive power supply. With real-time prices come incentives to make investments (e.g., in capacitors) to hedge these prices; however, because the price may be zero most of the time such needed investment and hedging may only occur after

a shortage condition becomes apparent. Reactive power would be paid for to support the reactive power use of the transmission system and load.

The process could be viewed as an extension of the traditional co-optimization of real power and operating reserves, which results in dispatch instructions that are consistent with the pricing signals. For instance, a supplier of ancillary services receives a price from the market that takes into account any lost opportunity cost of not supplying energy and thus has the incentive to supply the reserves rather than energy. Similar pricing can occur for reactive power. The price could be established in either of two ways.

i. Bid-Based

Suppliers could bid reactive power prices and quantities into the market and receive a market clearing price for the quantity supplied. Because real and reactive power are jointly produced, the structure of these bids could be complex. Because the D-curve determines the feasible set of real and reactive power production, separate independent price quantity bids for real and reactive power are likely to lead to infeasible or inefficient dispatch instruction. Merchant transmission elements could also offer reactive services under this approach.

ii. Based on Highest Opportunity Costs

This approach would allow suppliers to be paid a price based on the highest opportunity costs of those participants supplying reactive power to the market while meeting the system needs at lowest total (bid) cost. As mentioned above, the cost to supply reactive power by most transmission elements is zero and as such would generally be restricted to bids at or near zero under this approach.

Because real and reactive power are jointly produced by generation sources, their bids would be composed of a real power supply curve and the applicable capability curve (D-curve). More detail on this is contained in the technical appendices. Suppliers will have the incentive to voluntarily invest in reactive power capability because the market clearing mechanism could provide fixed-cost recovery. Those responsible for reactive power consumption, both end-use and transmission-related, should pay for the supply.

A more sophisticated alternative might even allow bids for reactive power supply outside of the standard D-curve operating parameters to meet system needs during scarcity situations. Such supply bids could compensate generators for additional wear and tear on the unit for supplies outside of the standard operating bounds of the unit. This might be particularly useful in emergency conditions to maintain reliability and avoid voltage collapse.

Allowing market clearing prices also could support bids by load and transmission suppliers. This may provide increased reliability during critical times. For instance, a transmission owner may be willing to incur the additional maintenance costs of running equipment beyond normal operating parameters for a period of time in exchange for the additional compensation from the reactive power market. Additionally, load response resources could also benefit from such pricing. For instance, reduced air-conditioning load during peak periods can provide valuable relief to a system's reactive power needs.

Developing software to allow efficient pricing of reactive power in real time could be a barrier to developing a real-time market. Additional software development will be needed to implement an approach that simultaneously optimizes real power, reactive power and voltage levels. However, it is unclear whether the benefits of such development would warrant the investment costs in terms of software development and market complexity. The opportunities for short-run efficiency gains from the system, however, are difficult to deny. The development of software for improved reliability and pricing tools are joint costs. The market and reliability needs are driven from the same underlying system constraints. Software development taking both needs into account can provide market participants with lower total system costs and provide more benefit than allowing the software for both needs to be developed independently.

Administratively Determined Prices or Pricing Formula Announced in Advance. Another method is to pay generators a predetermined price for the reactive power, or a price based on a predetermined formula. This method is currently used in several countries. These administratively determined prices may include unit-specific cost-of-service payments based on a common rate formula. They may also be location specific or may feature a uniform systemwide price for supply.

This approach would provide an incentive for reactive power suppliers to be available to the extent that the payment exceeded the marginal costs of supply. However, it is possible that when the system is most stressed, the opportunity costs are likely to be the highest. Thus, the incentive to supply reactive power may not be there when it is needed most. Further, in normal operating periods, prices significantly different than actual operating costs can lead to inefficient dispatch and higher customer costs.

Pricing Options Summary

As noted, there at least two ways to compensate reactive power providers. One way is to pay them in advance for their reactive power capability (capacity) based on reliability needs. A second way is to pay them in real time for their actual reactive power production and reserves. While it is possible to rely on only one of these ways, the methods are not mutually exclusive and, indeed, there may be benefits to using both methods. Each of the approaches has its own particular advantages as well as drawbacks. For instance, the pricing options that may show the most promise in terms of market efficiency may have the highest administrative costs and introduce complexity that is unacceptable to some market participants. Some of the simpler and more traditional approaches to reactive power procurement and pricing have some undesired incentives that lead to inefficient investment due to poor market signals or the lack of an independent system operator.

Conclusions, Recommendations and Questions

Conclusions and Recommendations

Reactive power is important for the reliable operation of the bulk power system. The value of reactive power is primarily for reliability, but it can also allow additional transfer of real power. The value of reactive power is highly locational, but this is not fully reflected in the Commission's rate or market designs. The optimal approach to reactive power market design and reliability involves and links generation, transmission and load.

Earlier in the paper, in the Executive Summary and at the beginning of Chapter 5, we identified six problems and concerns regarding the current procurement practices and pricing policies for reactive power. We make four broad recommendations to address these problems and concerns:

1. Reactive power reliability needs should be assessed locally, based on clear national standards.
2. These needs should be procured in an efficient and reliable manner.
3. Those who benefit from the reactive power should be charged for it.
4. All providers of reactive power should be paid, and on a nondiscriminatory basis.

Below, we discuss in more detail our recommendations to address these problems and concerns.

1. Discriminatory compensation.
   a. Transmission-based suppliers of reactive capability receive compensation, yet many generation-based suppliers are not compensated for reactive power capability that aids in system reliability.
   b. Independent generation resources may not always be compensated for providing reactive power support to the grid in areas where other generators affiliated with vertically integrated transmission owners receive cost-of-service payments for providing similar service, despite the Commission's policy requiring comparability.

Recommendation: All providers of reactive power, including owners of transmission equipment, independent generators, and generators owned or

---

affiliated with the transmission provider, should be paid on a nondiscriminatory basis. In some control areas, generators owned by the transmission provider are paid for reactive power while other generators are not. Such discrimination is poor public policy and could be considered to be undue discrimination under the Federal Power Act. Comparability has been a bedrock principle of open access and competitive market development. The Commission's general policy favoring comparability should apply in the reactive power context. Pricing and market design should be independent of ownership. Thus, independent generators should be eligible for the same compensation for reactive power as generators owned or affiliated with the transmission provider providing comparable service. Otherwise, the transmission provider's generation will have an unfair commercial advantage, independent power producers will have less incentive to enter the market (even when they have lower costs) and the costs of producing reactive power will be higher than necessary. Of course, compensation should be based on the system's needs for reactive power.

Order No. 888 was implemented when the merchant generation sector was relatively small. In light of the Large Generator Interconnection Rule, the Commission should review the methodology of Opinion No. 440 and, in particular, its effect on investment incentives. Further, the Commission should streamline the process for filing and collecting Opinion No. 440 rates to eliminate the greater regulatory burden imposed on independent generators for receiving reactive power compensation, relative to affiliated generators.

With the advent of new technology, equipment that supplies reactive power comes in smaller increments and can be made mobile, e.g., truck mounted. These characteristics allow for temporary or permanent solutions for considerably less investment and lower sunk costs. Current entry rules are a barrier to this technology. However, if this barrier were removed, market power in reactive power markets could be a far smaller problem because entry and exit could become much easier. We need a discussion of how this affects the Commission's policy on market design in general and for transmission in particular.

2. Rigid but imprecise interconnection standards that are insensitive to local needs. Interconnection standards generally require a standardized

generation power factor for new generation. But local needs often vary from the standards. Some locations may have higher reactive power needs than the standard, while other locations may have smaller needs. Moreover, the standards are imprecise in important respects. For example, the standards do not specify on which side of the step-up transformer, and exactly how, the power factor is to be measured.

Recommendation: Clear and precise interconnection standards should be developed that are sensitive to local needs, but that comply with generally applicable national reliability standards.

3. Lack of transparency and consistency in planning and procurement. The reactive power planning standards and procurement processes are not transparent. Alternative solutions to provide needed reactive power capability may be available, but currently these options might not be adequately considered.

Recommendation: Current rules and definitions have different interpretations and need to be more fully developed to avoid disputes and poor investment decisions. For example, there appears to be no unambiguous definition of the power factor requirement. Further, the power factor requirement does not translate into the amount of reactive power that should or could be available. "Good utility practice" is often invoked as the design criteria for reactive power, but "good utility practice" is not well defined and in most cases has not evolved at the same pace as the market. Full discussion of the meaning of "good utility practice" for future reactive power requirements is needed. Good citizenship and rules should not be the sole approach to investment in reactive power capability.

Currently, system planning for reactive power and procuring reactive power for reliability are less transparent than they could be. Transparency and better documentation in system planning are needed to demystify the process of planning for reactive power capability. Reactive power supply and consumption, as well as prices, should be publicly reported. Marginal prices are a simple calculation after the optimal power flow is calculated. They are not costly to calculate and publish.

4. Poor financial incentives to provide or consume reactive power.
   a. Many market participants that could provide additional reactive power capability to the system have little incentive to do so. Price signals that could encourage additional investment are limited.
   b. In many cases load response and load-side investment could reduce the need for reactive power capability in the system, but incentives to encourage efficient participation by load are limited.

Recommendation. The market design should align financial compensation and incentives with desired outcomes to ensure that adequate reactive power is available and produced in the right locations in order to maintain reliability and meet load at the lowest reasonable cost. Some have a different view – that independent generators should be obligated to provide a specified minimum capability to produce reactive power without compensation as a condition of interconnecting to the grid, but we think that this view will not encourage optimal investment and production of reactive power. If independent generators aren't paid for providing reactive power capability, some may elect not to enter the market, and some existing generators may elect to retire sooner than if payments were made. Suppliers of reactive power should be compensated for providing reactive power and reactive power capability. Similarly, once capability payments are received, capability tests for reactive power should be a routine part of reliability procedures and penalties should be assessed for test failures. For the present, while longer term options are being further studied, we recommend considering a policy of paying market participants for the reactive power that they produce on the system operator's instruction based either on the unit's own opportunity cost or on an administratively determined price or price formula announced in advance. Further, we recommend considering a policy of charging consumers for consuming reactive power from the transmission system. Such payments and charges would encourage market participants to produce or consume reactive power where it is needed.

The market rules should allow greater compensation for reactive power capability having greater quality and value, just as they do for real power operating reserves. For example, reactive power capability from dynamic sources is more valuable than from static sources, because dynamic sources can adjust their production or consumption of reactive power much more

quickly when needed to maintain voltage and, thus, prevent a voltage collapse. Thus, reactive capability from dynamic sources should be paid more than capability from static sources at the same location. This is consistent with the policy of paying higher prices for faster-response (and thus, higher quality) operating reserves for real power. For example, 10-minute spinning reserves are generally more valuable – and are generally paid more – than 30-minute nonspinning reserves at the same location and time because the former can respond to dispatch instruction more quickly than the latter. However, reactive power that is actually produced or consumed at a given location and time has the same value whether it is provided by a static or dynamic source. Thus, the price faced by all reactive power providers in a spot market at a given location and time should be the same, regardless of the source. This policy is consistent with the approach followed in spot auction markets for real power in ISO markets, where all suppliers at a given location and time are paid the same price for their real power production.

5. Poor incentives for some system operators to procure reactive power and reactive power capability at least cost. System operators outside of RTOs and ISOs that are regulated transmission owners may lack the incentives to consider all available sources of reactive power. That is because cost-of-service regulation generally rewards capital investment, even when purchasing from a third party would be a less costly alternative.

Recommendation: The Commission should pay careful attention to ensure that transmission providers procure reactive power supply and capability at least cost, and that the rates charged by the transmission provider reflect such least-cost procurement.

6. Failure of system operators to adjust reactive power instructions so as to fully optimize the dispatch. Often, a range of reactive power production levels would fully meet the reliability requirements of a transmission system. However, system operators typically choose the level that meets specified guidelines, even though other levels within the range would allow the demands for real power to be met at a lower total cost. A related issue is that the software for implementing such reactive power optimization is not currently available.

Recommendation: System operators should begin the process of developing the capability for determining how to adjust reactive power levels so as to fully optimize the dispatch. Part of this process would involve charging or paying market participants for reactive power on a real-time basis. Complete, efficient market design for reactive power could reduce overall costs substantially. Some preliminary simulations reported in this paper suggest that a fuller consideration of reactive power in real time spot markets in conjunction with real power markets may have the potential to reduce the total costs of meeting load. By not properly pricing reactive power, we may be missing opportunities to further increase reliability and efficiency. Fully incorporating reactive power in the dispatch decision through a bid-based reactive power market is a relatively new idea, and we believe it is too soon to implement one. This design needs a full and open discussion and some empirical observation before additional steps are taken. Simulation and experimentation are needed to better understand the effects of alternative auction market designs for reactive power. The appendices attempt to lay the groundwork for such a discussion. In addition, the software and other costs of developing a reactive power auction market should be understood.

There is much speculation and little empirical knowledge of the value of reactive power or what spot market prices for reactive power would be if there were jointly optimized day-ahead and real-time markets for reactive power. To provide better information on these values, RTOs and ISOs should calculate reactive power marginal values (or prices) and post them on the same basis as real power prices.

Short-term versus long-term reform. This paper is intended to begin a discussion of regulatory policies affecting reactive power. Any changes in policy resulting from this discussion are likely to take some time to implement. Some changes are likely to be made more easily and quickly than others. For example, policies that promote comparability are likely to be more easily made, and we recommend working to implement them in the near term. These policies include (1) clarifying the requirements and compensation rules for providing reactive power, as well as the definitions underlying these requirements and rules, (2) creating incentives that encourage desired behavior, (3) streamlining the process for compensating independent

generators for reactive power capability and provision to make the process comparable to that for affiliated generators and (4) making reactive power procurement and compensation more transparent, for example by calculating and publishing reactive power production, consumption and prices on a comparable basis to real power. Other policy changes involve more complex issues, and will require more time to consider. Policy changes that involve a complete market redesign will thus need to be implemented over the longer term. The ultimate goal should be an integrated set of co-optimized markets with bilateral markets relatively free from federal regulation. This goal requires research, software development, education and testing, and is likely to require 5 to 10 years to fully implement.

Questions

We intend this paper to stimulate a public discussion about the proper regulatory policy toward reactive power pricing and market design. To help advance this dialogue, we invite public comment on the questions below.

General

Should transmission providers report the value of real and reactive power on their systems? Would this help make better locational investment decisions?

By not properly pricing reactive power, are we missing opportunities to further increase reliability and efficiency?

Should reactive power reserves be differentiated by quality as are real power reserves? Should dynamic reactive power be differentiated from static reactive power?

What are the relationships and differences among standard transmission assets, e.g., capacitors, FACTS devices and generators in reactive power supplied? Where do FACTS fit in? What is the effect of different outage rates?

How, what and when are dispatch signals for reactive power sent to market participants?

Should the general approach to voltage scheduling be reexamined to improve reliability and efficiency?

Should generators be required to supply an identified range of reactive power without compensation?

Reliability and Engineering

System Planning

How are reactive power reserves determined? How are reactive power reserves quantified?

Do we have enough reactive power capability in our generators to meet the reliability needs of our power system? If so, how do we know?

What should the static reactive power capabilities (or reserves) be? What should the dynamic reactive power capabilities be? What should the reactive power capabilities be used for?

Should reactive power reserve requirements be locational and/or better defined like real power reserves?

Should reactive power reserves be procured competitively?

Are there optimal design characteristics with respect to reactive power for generators, transmission and load? If so, how are they derived? Or, do they depend on system characteristics? If so, how are they derived?

For Generation

What is "good utility practice" for reactive power supply and reserves from generators?

What reactive power capabilities, if any, should be required of generators without compensation?

Is a generic power factor requirement the best approach to reactive power capabilities or should it be based on system requirements?

Are the interconnection standards with respect to reactive power capability clear? Is it clear what it means to have a 0.95 power factor requirement in the Large Generator Interconnection Procedures (LGIP)?

Should the power factor requirement for generators be measured at the high or the low side of the step-up transformer?

Should there be the reactive power requirements for non-synchronous generators (wind, solar)? If so what?

What is the role of distributed generation in providing reactive power?

What are the options for reactive power output as a function of investment in generator design?

Does it make economic sense to oversize the generator or the turbine?

Should required reactive power capability differ based on location on the system? For instance, should we allow generators distant from load to have less capability?

What are the advantages of supplying dynamic reactive power locally from distributed energy resources (DER)?

For Transmission

Should there be interconnection standards with respect to merchant transmission?

Can thermal transmission constraints be relieved by supplying or consuming reactive power? If so, how and to what extent?

Can nonthermal transmission constraints be relieved by supplying or consuming reactive power? If so, how and to what extent?

Systems Operators

How are voltage schedules determined? Who decides? What are the criteria? Are they optimized? Are generators required to operate at a given power factor, or are they required to maintain a specified voltage? Are generation costs incorporated into voltage schedule decisions?

Should the approach to voltage management and scheduling be re-examined? How does voltage scheduling affect economic operations? Should there be incentives for voltage management?

Should system operators take transmission lines out of service to balance reactive power?

What instructions or signals (prices, real power, reactive power, voltage, frequency) does the system operator send to generators, transmission and load? (In particular, for reactive power)

What information does the system operator have on generator capabilities and how is it used?

Under what circumstances might a generator be required to reduce real power output due to a shortage of reactive power?

Are phase shifters set to get optimal system performance? If so, how?

Are D-curve parameters of each generator available to the control area or system operator?

Costs, Pricing and Markets

Costs

What are the cost differences among reactive power from capacitors, FACTS and generators?

What is the incremental investment cost for generator reactive power capability?

Order No. 888 Rate Design

Are independent power suppliers being compensated comparably to the generation supplied that is owned by transmission owners?

Can the capital costs of reactive power capability be effectively unbundled? Should reactive power pricing be unbundled? If so, how?

Does Opinion No. 440 properly encourage efficient reactive power capabilities? If so, how? If not, how should it be changed?

How can we streamline the Opinion No. 440 process for establishing rates?

How does the reactive power capability of existing and interconnecting independent power producers impact system reliability?

RTO Markets

What software advances are needed for efficient and reliable reactive power markets?

Should reactive power capability requirements be locational and procured in capacity markets?

How are generator capabilities used in the ISO/RTO markets?

How should merchant generators and transmission be compensated for the capability to provide reactive power?

How should distributed energy resources (DER) be compensated for supplying dynamic reactive power?

How should reactive power rates and markets be designed in RTOs? Should there be different prices for reactive power produced by static and dynamic sources?

Are there incentives for generation, transmission and load to increase

their capability, e.g., by increased cooling where needed? If not, why not?

Should reactive power be paid opportunity cost compensation based on the real power price?

Should a separate reactive power capacity market be developed? If so, what should the capacity supply obligation time frame be? Daily? Monthly? Annually?

Should there be different types of payments or markets for reactive power from different sources (generators, capacitors, SVC, STATCOM, synchronous condensers, etc)?

What are the computational impediments to including reactive power in the day-ahead and real-time markets?

What are the noncomputational impediments to including reactive power in the day-ahead and real-time markets?

What kind of market power mitigation would be needed?

What is the magnitude of reactive power value (price) relative to real prices?

What is the volatility of reactive value (price) compared to real power?

How would a reactive power market reflect the high opportunity cost of insufficient reactive power (i.e., a cascading blackout)? Is the market suspended for emergency situations?

Glossary of Terms

Alternating Current (AC): An electric current that periodically reverses its direction. In North America, an electric current that reverses direction 120 times per second, thus pulsating 60 times a second. Each pulse equals one cycle.

Armature: The part of the generator in which an electric field is induced (for large synchronous generators it is the stator, a cylinder with coils of wire around it).

Capacitance: A property of electric circuits that supplies reactive power.

Capacitor Bank: A group of switched capacitors.

Circuit Breaker: A switch used to connect components of an electric transmission network.

Competition, perfect: An ideal market structure characterized by a large number of small firms, identical products sold by all firms, freedom of entry into and exit out of the industry, and perfect knowledge of prices and technology.

Competition, imperfect: A market structure characterized by two or more sellers and buyers that fail to match the criteria of perfect competition with one or more buyers or sellers having a perceptible influence on price.

Complete Pricing: A situation in which the supplier is paid for all goods and services provided and the customer pays for all goods and services consumed.

Consumption: The use of a product or service (such as reactive power).

Contingency: An outage of a line, transformer, or generator. Power systems planners study major contingencies so that the system can operate through likely contingencies without a blackout.

Core End: The ends of the generator armature; the ends of the armature overheat before the rest of the armature when a generator is consuming reactive power.

Cost, fixed: A cost that does not vary with the amount of output produced. However, in contrast to a sunk cost, the cost can be entirely avoided if no output is produced. For example, the cost of equipment is often a fixed cost in that the same equipment cost is incurred regardless of how much output is produced from the equipment. However, the equipment cost could be avoided by not purchasing the equipment, and thus, not producing any output. In addition, the equipment cost would be fixed but not sunk if the purchased equipment could be sold after it is purchased (and thus, the equipment cost would be avoided after the sale) if the owner no longer wishes to produce output.

Cost, sunk: A cost that (1) does not vary with the amount of output produced, and (2) cannot be avoided even if no output is produced. For example, if a piece of equipment has been purchased and has no value to anyone other than the present owner, the cost of the equipment is a sunk cost, because the owner could not sell the equipment in order to avoid the equipment cost in the future.

D-Curve: The set of curves defining the real and reactive power capacities of a generator; also known as the generator capability curve, or generator capability set. The curves are shaped like a capital letter D, hence the name D-curve.

Direct Current (DC): An electric current that flows in only one direction.

Distributed Generator: A small generator connected to an electric distribution system.

Dynamic Var (D-var): A voltage regulation system manufactured by American Superconductor, used for reactive power support and classified as a FACTS device.

Efficiency: As a term in economics, efficiency is a state in which resources are used in a way that produces the maximum economic value to members of society.

Exciter: The part of a synchronous generator that provides the field current. It can be a DC motor connected to the field of the generator, or an electronic DC power supply.

Externality: The effect of a purchase or use decision by one set of parties on others who did not have a choice and whose interests were not taken into account. In a free market, an inefficient amount, too much or too little of the good, will be consumed from the point of view of society.

Field: The part of the generator that induces an electric field in the armature (for large synchronous generators it is the rotor, a spinning electromagnet)

Filter: A device to minimize oscillations at certain frequencies in the transmission system. Filters are installed with switching devices such as FACTS and HVDC to mitigate the effects of high-frequency switching on the transmission system.

Flexible Alternating Current Transmission System (FACTS): FACTS devices are technologies that increase flexibility of transmission systems by allowing control of power flows and increasing stability limits of transmission lines. There are several varieties of FACTS devices, including SVCs, STATCOMs and D-vars.

Fuel Adjustment Clause: A clause in the tariff of a utility subject to cost-based regulation that allows the utility to quickly adjust its prices when its fuel costs change, so that the utility exactly recovers its fuel costs.

Generator Capability Set: The set of curves that define a generator's real and reactive power capability. (See D-curve)

Generator Step-Up Transformer: The transformer that converts low voltage power from a generator to high voltage power, and connects the generator to the high voltage transmission system.

Good, private: A good which possesses two properties: (1) excludability (also referred in this context as rivalry) - cannot be consumed by everybody since consumption by one person reduces or excludes consumption by another, and (2) depletability (it is finite).

Good, public: A good which possesses two properties: 1) it is non-rivalrous, meaning that its benefits do not exhibit scarcity from an individual point of view; once it has been

produced, each person can benefit from it without diminishing anyone else's enjoyment 2) it is non-excludable, meaning that once it has been created, it is impossible to prevent people from gaining access to the good.

High Temperature Superconducting (HTS): Cables and wires made of superconducting materials, cooled with liquid hydrogen or nitrogen, operated at relatively high temperatures of up to -320 degrees Fahrenheit, in comparison to superconducting materials that operate at near absolute zero, or -457 degrees Fahrenheit.

High Voltage DC (HVDC): High voltage DC transmission lines have AC-DC and DC-AC converters at each end and transmit power using direct current. The converter stations can be independently set to supply or consume reactive power, and the lines do not supply or consume reactive power since they are transmitting dc power.

Independent System Operator (ISO): The operator of a transmission system that is independent of market participants. The Commission's Order No. 888 established eleven principles for qualifying for ISO status, including that (1) its governance be fair and non-discriminatory, (2) the ISO and its employees have no financial interest in any market participant, (3) it provide open access to the transmission system at non-pancaked rates under a single tariff applicable to all users, (4) it has primary responsibility for ensuring short-term reliability of grid operations, (5) it has control over the operation of interconnected transmission facilities within its region, (6) it identifies and takes operational actions to relieve constraints on its system, (7) it has appropriate incentives for efficient

management and administration and procures services in an open competitive market, (8) its transmission and ancillary service pricing policies promote efficient use of and investment in generation, transmission and consumption, (9) it makes transmission system information publicly available via an electronic information network, (10) it develops mechanisms to coordinate with neighboring control areas, and (11) it establishes an ADR process to resolve disputes.

Inductance: A property of electric circuits that consumes reactive power.

Installed capacity (ICAP): The capacity of a generation or demand-side resource that meets certain requirements established under the tariffs or operating agreements of certain ISOs and that load serving entities within the ISO's control area must procure. The requirements typically include bidding into the ISO's spot markets, curtailing energy exports during emergencies within the ISO's control area in order to make the capacity's energy available to the ISO's control area, and being available (and thus, not on a planned or forced outage) during a specified portion of the year.

Insulated Gate Bipolar Transistor (IGBT): A newer type of semiconductor based electronic switch used in high voltage applications.

kVA: A measure of apparent power equal to 1,000 volt-amperes.

kvar: A measure of reactive power equal to 1,000 reactive volt-amperes.

kvarh: A measure of reactive energy equal to 1,000 reactive volt-ampere hours.

kW: A measure of real power equal to 1,000 watts.

kWh: A measure of real energy equal to 1,000 watt-hours.

Lagging Power Factor: When the current phase angle is smaller than the voltage phase angle, the current lags the voltage, and the power factor is lagging.

Leading Power Factor: When the current phase angle is larger than the voltage phase angle, the current leads the voltage, and the power factor is leading.

Load: The amount of electric energy delivered to customers on a system.

Large Generator Interconnection Procedures (LGIP): Standard procedures for interconnecting large generators with transmission facilities that the Commission required all public utilities that own, control or operate transmission facilities to file, in Order No. 2003, issued on July 24, 2003.

Marginal Cost: The additional cost incurred to provide a small additional increment of a product or service, such as electric energy.

Market Power: The ability of a market participant to change the market price away from the competitive level by withholding from the market. Market power can be held by either a seller or a buyer. For a seller, market power is the ability to increase the market price above the competitive level by withholding supply from the market. For a buyer, market power is the ability to lower the market price below the competitive level by reducing its purchases (i.e., by withholding demand from the market).

Monopoly: Market structure in which only a single market participant supplies a good or a service.

Monopsony: Market structure in which only a single market participant is a buyer of a good or a service.

MVA: A measure of apparent power equal to one million volt-amperes.

Mvar: A measure of reactive power equal to one million reactive volt-amperes.

Mvarh: A measure of reactive energy equal to one million reactive volt-ampere hours.

MW: A measure of real power equal to one million watts.

MWh: A measure of real energy equal to one million watt-hours.

Optimal Power Flow (OPF): An optimization problem that solves real and reactive power dispatch at minimum cost, subject to system constraints.

Overexcited: The generator operating mode where the generator is supplying reactive power.

Power Factor (PF): (1) The ratio of real power to apparent power, also the cosine of the phase angle between line current and voltage (2) A measure of real power in relation to reactive power. A high power factor means that relatively more actually useful power is being taken or produced relative to the amount of reactive power. A lower power factor means that there is relatively more reactive power taken than real power.

Power Factor, capability or design: The range of power factors in which the generator is designed to operate. Although not formally defined, it is commonly understood to be the range of power factor determined by the generator's maximum supply and consumption of reactive power when the generator outputs rated real power, at the operating limit of the turbine. Alternatively, a point on the D-curve where significant decrease in real power is necessary to produce additional reactive power.

Power Factor, nameplate: The power factor at the points on the capability curve of the generator where the stator constraint intersects the field current constraint.

Power Factor, operating: The power factor (ratio of real power to apparent power) produced or consumed at a point in time when the generator is operating.

Prime Mover: The part of the generator that moves the rotor, a water, steam or gas turbine for electric power generators.

Qualifying Facility: A cogeneration or small power production facility that qualifies under FERC's regulations and PURPA to sell electric energy and capacity to a utility at the utility's avoided cost. A cogeneration power production facility produces electricity and useful heat or steam used for industrial, commercial, heating or cooling purposes. A small power production facility has a capacity less than 80 MW, with a primary energy source of biomass, waste, geothermal, or renewable resources (including hydro).

Reactive Power: The portion of power that establishes and maintains electric and magnetic fields in AC equipment. Reactive power is necessary for transporting AC power over transmission lines, and for operating magnetic equipment, including rotating machinery and transformers.

Regional Transmission Organization (RTO): Entity responsible for the operation of the transmission network under Order 2000. Minimum characteristics of an RTO include (1) independence from market participants, (2) appropriate scope and regional configuration, (3) operational authority for all facilities under the RTO's control, and (4) exclusive authority to maintain short-term reliability. The minimum functions of an RTO are (1) tariff administration and design, (2) congestion management, (3) parallel path flow, (4) ancillary services, (5) OASIS with Total Transmission Capability (TTC) and Available Transmission Capability (ATC), (6) market monitoring, (7) planning and expansion, and (8) interregional coordination.

Rotor: The rotating part of the generator.

Second Best (Second Best Efficient): The preferred allocation of goods and services or set of allocations that does not achieve an efficient allocation. When only a limited number of policy tools are available, second best allocations generally maximize a social welfare function.

Static Compensator (STATCOM): A FACTS device similar to an SVC, but using switches called Insulated Gate Bipolar Transistors (IGBTs) to supply or consume reactive power without capacitors and inductors.

Static Var Compensator (SVC): A FACTS device consisting of electronic switches called thyristors connected to capacitors and inductors

that can supply or consume reactive power.

Stator: The stationary part of a generator.

Supervisory Control and Data Acquisition (SCADA): The system of meters and communication equipment that sends status information of electric power system equipment to control centers.

Supply: The willingness of producers to sell a given amount of goods and services for a price at a particular time.

Surge Impedance Loading (SIL): Transmission line loading when the reactive power supplied by line capacitance equals the reactive power consumed by line inductance.

Switched Shunt Capacitor: A capacitor connected to a transmission line through a switch.

Synchronous Condenser: An electric generator not connected to a turbine that supplies or consumes reactive power without supplying real power.

Synchronous Generator: An electric machine that runs in synchronism, at the same frequency, as other machines on a network to produce real and reactive power.

System Operator (SO): The entity that operates the system. It gives the dispatch orders to generators, transmission and load. A system operator is independent when it has no financial interest in the electricity assets.

Supervar: A synchronous condenser with high temperature superconducting cables for improved efficiency.

Thermal Limit: An operating limit determined by thermal limits of materials in a device.

Thyristor: A type of semiconductor based electronic switch.

Transmission Operator (TO): The entity that operates transmission. It executes dispatch orders from the SO.

Transformer Tap: Electronic switches that adjust the amount of reactive power and voltage on one side of the transformer by changing reactive power and voltage on the other side.

Turbine: Rotary engine in which the kinetic energy of a moving fluid (water, steam or gas) is converted into mechanical energy by causing a bladed rotor to rotate.

Underexcited: The generator operating mode where the generator is consuming reactive power.

Var: Volt-ampere-reactive; var is a measure of reactive power. By comparison, real power is measured in watts.

Voltage Collapse: A dynamic phenomenon in power systems where voltage in the network becomes unstable, generators trip off line, and blackouts occur.

Literature Review of Reactive Power Markets

During the era of vertically integrated utilities, reactive power was viewed strictly as an engineering issue, something to be built sufficiently into the system in a centralized way. Studies conducted before restructuring focused on whether reactive power and other alternating current characteristics were being represented correctly in engineering calculations, such as contingency models and distribution factors. (Ilic-Spong and Phadke, 1986; Lee and Chen, 1992; see end-matter references for complete identification of these and other references in the text). Other engineering research was beginning to explore the role reactive power controls had in increasing the functioning of the grid, perhaps in obviating (or at least postponing) some system upgrades to generation and transmission. (Ilic, 1991)

Beginning in the early 1980's, researchers were beginning to think about alternate ways of pricing electricity to achieve specific objective, such as maximal social welfare or system reliability. Caramanis et. al. (1982) presented a "new concept" in electricity pricing, a method which evolved into what is now known as locational pricing. In this work, it was suggested that a market for electricity can efficiently set location-specific prices based on instantaneous supply and demand that promote consumption patterns that benefit the transmission system. Implementing separate prices for real and reactive power would produce the most efficient pricing outcomes, even though the authors assert that the price of reactive power will often

be insignificant compared to real power prices. The calculations for real power from this seminal work were expanded upon by Schweppe et. al. (1987); however, this later work does not discuss reactive power. Although some of the early economic publications mention reactive power or various schemes for voltage control, and indicate separate prices might be desirable, none rigorously consider the implications of reactive power prices or mechanisms for setting these prices. (Outhred and Schweppe, 1980)

In the early 1990s, with the restructuring of the industry eminent, researchers began looking more seriously at pricing both real and reactive power in an economically efficient way. The new emphasis on markets for electricity created a new focus on reactive power pricing in the literature: whether it was important, how it should be done, what would be the resulting prices. Baughman and Siddiqi (1991) presented an early argument that because the physics of real and reactive power are so closely tied, simultaneous pricing of real and reactive power would be important to the development of electricity markets and that in the presence of voltage constraints, reactive power prices can be extremely high.

In 1993, Hogan made the claim that because they do not include the effect of reactive power, DC load models are not sufficient to determine real power prices of systems with voltage constraints, and that the price of reactive power is not negligible and does not have a simplistic

relationship to real power. He presented a three-node example that showed marginal reactive power prices soaring to equal those of real power. Because there was no simple relationship between real and reactive power, and because reactive power prices can be significant, Hogan argued that electricity markets need explicitly to include prices for reactive power.

This argument was countered in 1994 by Kahn and Baldick, who showed that Hogan's example system was artificially constrained - that one of the generators was not allowed to produce more reactive power when it could have done so. When the test system was re-dispatched in a more efficient way, the price of reactive power (in the presence of voltage constraints) dropped again to be a fraction of the real power price. The conclusion was that with appropriate centralized planning, the cost of providing enough reactive power to a system is negligible, and this need for centralized planning was used to argue for regional transmission groups.

After the Hogan-Kahn-Baldick debate, it became accepted that reactive power management had to adapt in this new, restructured era. Now in addition to effecting grid security, reactive power and voltage control played a part in determining market efficiency (Ilic and Yu, 1999). Much of the research that followed focused on alternative ways to manage and dispatch reactive power in the future, including whether desirable system voltage profiles exist and how could they be determined. There was also increased production of technical and nontechnical (Sauer, 2003) papers discussing reactive power, presumably because

a wider audience – wider than just the engineering community – needed to know what it was, how it worked and why it was important. Kirby and Hirst (1997) discussed the role of transmission in voltage control, characteristics of voltage control equipment and strategies for voltage control management. Several years later another report came out that described reactive power balance, reactive power and transmission and black-start techniques, generator reactive capability (comparing actual performance with manufacturer name plate characteristics) and the importance of optimizing transformer tap positions for producing and absorbing reactive power (Adibi, 2000). Alvarado et. al. (2003) produced a comprehensive literature and market review of reactive power pricing strategies intended to help the Transmission Administrator of Alberta, Ltd., make a determination of how to handle reactive power in their system. This study, while making no specific recommendations for Alberta, outlined possible areas of action for improving investment and dispatch decisions, among others.

Some of the more technical papers to emerge at this time focused on the implications of inductive load (Meliopoulos et. al., 1999), advances in over excitation region control and generator behavior in this region (Murdoch et. al., 2001), and the importance of determining critical buses for voltage stability, rather than market concentration, to combat market power (Zambroni de Souza et. al., 2001). Ilic et. al. (2004) presented a technical analysis of limitations of DC power flows to adequately represent the effects of reactive power and

generator reactive power limits. The paper examines differences in LMPs resulting from DC OPF and an AC OPF with reactive power limitations, and attributes these differences to allocating line capacity to reactive power in the AC OPF case.

In looking to the future of markets and policy, two general areas of research developed. One examines decentralized incentives for reactive power capacity and dispatch, how optimal power flows (OPFs) can be modified to incorporate reactive power costs, and what price signals would best capture the incentives for building capacity and ensuring performance. The other focuses on the role of centralized planning and control of reactive power planning and production in the era of restructured electricity markets.

Two case studies were published in 1995 that represent the two sides of this new research. Both described methods for dispatching reactive power, but one paper described a centralized reactive power management program, which serves to ensure that efficient amounts of reactive power support are supplied by the transmission and distribution system. It also described how to meet unexpected reactive power demand with generators (Nedwick et. al., 1995). The other paper explained reactive power dispatch based on two complimentary OPF calculations, one minimizing cost to obtain economic benefits, and the other minimizing the amount of "control action" – the number of physical controls that change – in order to maintain physical practicality (Dandachi et. al., 1995). Neither paper advocated pure market economics or centralized control, but each

placed greater emphasis on one or the other, and this is how most of the debate has been framed since the mid-1990s.

In the following few years, researchers studied the new role of system operators in relation to reactive power and what function centralized planning and control should have. An integrated method for capacity planning was proposed based on OPF iterations, determining the best location and size of capacitor banks on a system (Chattopadhyay et. al., 1995). The Reactive Services Working Group at PJM proposed several short- and long-term strategies for combining centralized requirements and planning with decentralized bidding for capacity projects, along with a two-part tariff to encourage capacity and performance (PJM, 2001). Nobile and Bose (2002) suggested creating Voltage Control Areas (VCA) as a strategy for controlling voltage by blending centralized and decentralized control. Voltage set-points are determined by the VCA system operator, but decisions about dispatch to meet these set-points are based on economic bids and long-term contracts.

Meanwhile, several reports were published that examined the implication of using different objective functions in traditional OPF algorithms to optimize reactive power dispatch. These objectives included minimizing network losses, minimizing the movement of transmission devices (like transformer taps), maximizing social welfare and minimizing total costs (including implicit costs like changing transformer taps) (El-Keib and Ma, 1997; Weber et. al., 1998; Choi et. al., 1998; Lamont and Fu, 1999). These reports also looked at the

possibility of pricing reactive reserves, the cost of outages or reactive power curtailments and a responsive demand-side. One report attempted to internalize all aspects of the power system – all traditional OPF constraints as well as load frequency control, harmonic distortions and emission rates – into one set of prices in order to create a truly efficient market with minimal need for centralized planning or control (Baughman et al., 1997, two parts).

Because these studies used different test systems and different algorithms to compute reactive power prices it is difficult to compare resulting prices directly. That said, the magnitude of reactive power prices generally falls within the range of about one-tenth to one-half of real power prices, with larger ratios occurring because of voltage constraints, peak loading conditions or loads with low power factors. Although they no longer soar to the original Hogan levels, they are "significant," the authors state, in providing appropriate market signals (Siddiqi and Baughman, 1995; El-Keib and Ma, 1997; Weber et al., 1998; Choi et al., 1998).

Suggested strategies for pricing reactive power have evolved over the last 10 years from simplistic pricing methods – making reactive power production a noncompensated generator obligation, or basing the price on the level of real power output – to more complicated incentive structures. Initially, reactive power was considered almost too cheap to meter and should simply be the obligation of generators to provide, at least within their capability curve (Chattopadhyay et al., 1995; Hao and Papalexopoulos, 1997). Compensating

generators for opportunity cost, the loss of real power revenue when ramping down real power and ramping up reactive, has since become widely accepted (Sauer et al. 2001; Hao, 2003).

The Federal Energy Regulatory Commission (FERC) in 1995 published its Notice of Proposed Rulemaking directing that independent power producers generating real power should be required to provide some amount of reactive power. These generators should be compensated in a way comparable to traditional utility producers, and the price for reactive power should be based on the unbundled price of producing reactive power. Partly as a response to this, Kirsch and Singh (1995) explained how the reactive power pricing method suggested by FERC will result in prices that are either too high or too low. Alvarado et al. (1996) identified several problems with the way reactive power was being priced in real U.S. markets at the time, such as only localized demand was being priced, there were inconsistent assumptions about cost and there was no differentiation between the price of static reactive power (cheaper, provided by capacitor banks and other transmission facilities) and dynamic reactive power (more expensive, provided mainly by generators).

To fix these problems, researchers began looking into alternative, more sophisticated ways to determine prices. The relationship between real power flow and reactive power indicates it would be desirable to compensate reactive power producers for reactive power production allows more real power flow. El-Keib and Ma (1997) suggested that dispatching reactive power based on minimizing losses on

a system will compensate generators for producing reactive power even when operating within acceptable voltage limits, production that is typically uncompensated. The difference between supplying static and dynamic reactive power has also been widely discussed, and many advocate explicitly differentiated pricing for these two services (Alvarado, 1996; PJM, 2001). Many authors recognize the difference between encouraging investment in reactive power capability and inducing its production. A way to approach this distinction is with a two-part tariff, compensating both reactive capacity and performance (Chattopadhyay et.al., 1995; Hao and Papalexopoulos 1997; Kirby and Hirst, 1997; PJM 2001). Several of these publications describe the need for long-term contracts in markets for reactive power as a preventative measure against exercise of market power (Kirsch and Singh, 1995; Alvarado et. al., 1996; Nobile and Bose, 2002).

Another way to potentially use markets to value voltage regulation is to let market participants bid their desired level of voltage tolerance into the market. In this way, market participants can implicitly communicate their value for voltage, voltage regulation and reactive power. An additional benefit of recognizing different voltage needs is that relaxing voltage tolerances can improve the optimality of an OPF solution; incorporating voltage values as decision variables in an OPF calculation has the potential to reduce system costs. Exploration of this topic has only begun, but initial findings indicate that it is a promising area of research (Kim et. al. 2004).

At this point, there is no single widely accepted strategy for determining or encouraging appropriate investment in reactive power capability and production, but researchers from multiple disciplines (engineering, economics, policy) are expanding their knowledge of this subject and continuing to add to the dialogue.

References

M. M. Adibi, "Reactive Power Consideration" prepared for EPRI, 2000.

Fernando Alvarado, Romkaew Broehm, Laurence D. Kirsch and Alla Panvini, Retail Pricing of Reactive Power Service, *1996 EPRI Conference on Innovative Approaches to Electricity Pricing*, La Jolla, CA, March 27-29, 1996.

Fernando Alvarado, Blagoy Borissov and Laurence D. Kirsch, "Reactive Power as an Identifiable Ancillary Service," prepared by Lauritis R. Christensen Associates Inc. for Transmission Administrator of Alberta, Ltd. March 18, 2003.

Martin L. Baughman and Shams N. Siddiqi, "Real-Time Pricing of Reactive Power: Theory and Case Study Results," *IEEE Transactions on Power Systems*, Vol. 6, No. 1, pp. 23-29, February 1991.

M. L. Baughman, S.N. Siddiqi and J. W. Zarnikau, "Advanced Pricing in Electrical Systems. I. Theory," *IEEE Transactions on Power Systems,* Vol.12, No.1, pp.489-495, February 1997.

M. L. Baughman, S.N. Siddiqi and J. W. Zarnikau, "Advanced Pricing in Electrical Systems: II. Implications," *IEEE Transactions on Power Systems,* Vol.12, No.1, pp.496-502, February 1997.

M.C. Caramanis, R.E. Bohn, F.C. Schweppe, "Optimal Spot Pricing: Practice and Theory," *IEEE Transactions on Power Apparatus and Systems,* Vol. PAS-101, No. 9, pp. 3,234-3,245, September 1982.

D. Chattopadhyay, K. Bhattacharya and J. Parikh, "Optimal Reactive Power Planning and its Spot-Pricing: An Integrated Approach," *IEEE Transactions on Power Systems*, Vol.10, No.4, pp.2,014-2,020, November 1995.

J. Y. Choi, S. H. Rim and J. K. Park, "Optimal Real Time Pricing of Real and Reactive Powers," *IEEE Transactions on Power Systems,* Vol.13, No.4, pp.1,226-1,231, November 1998.

N.H. Dandachi, M.J. Rawlins, O. Alsac, M. Prais and B. Stott, "OPF for Reactive Pricing Studies on the NGC System," *Proceedings of the PICA 1995 Conference*, Salt Lake City, Utah, May 1995.

A. El-Keib and X. Ma, "Calculating Short-Run Marginal Costs of Active and Reactive Power Production," *IEEE Transactions on Power Systems.*,Vol.12, No.2, pp.559-565, May 1997.

Federal Energy Regulatory Commission, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, 70 FERC ¶ 61,357 (1995).

Shangyou Hao and A. Papalexopoulos, "Reactive Power Pricing and Management," *IEEE Transactions on Power Systems,* Vol.12, No.1, pp.95-104, February 1997.

Shangyou Hao, "A Reactive Power Management Proposal for Transmission Operators," *IEEE Transactions on Power Systems*, Vol. 18, No. 4, November 2003.

William W. Hogan, "Markets in Real Electric Networks Require Reactive Prices," *The Energy Journal*, Vol. 14, No. 3, pp. 171-200, 1993.

Marija Ilic-Spong and Arun Phadke, "Redistribution of Reactive Power Flow in Contingency Studies." *IEEE Transactions on Power Systems*, Vol. PWRS-1, No. 3, pp. 266-275, August 1986.

Marija Ilic, "A Survey of the Present State-of-the-Art Voltage Control with Emphasis on Potential Role of FACTS Devices," The International Workshop on Bulk System Voltage Phenomena, Voltage Stability and Security, Maryland, August 1991.

Marija Ilic and Chien-Ning Yu, "A Possible Framework for Market-Based Voltage/Reactive Power Control," IEEE Power Engineering Society Winter Meeting, New York, February 1999.

Marija Ilic, Marcelo Elizondo, Michael Patnik, Zayra Romo and Zhiyong Wu, "Economies of Scope and Value of Coordination in the Evolving Electric Power Systems," Carnegie Mellon Conference on Electricity Transmission in Deregulated Markets, Pittsburgh, Pennsylvania, December 15 – 16, 2004.

Edward Kahn and Ross Baldick, "Reactive Power is a Cheap Constraint," *The Energy Journal*, Vol. No. 4, 1994.

Seon Gu Kim, Hugh Outhred and Iain MacGill, "Commercialising Voltage Regulation in Nodal Electricity Spot Markets," Presentation at ESI2004, The Electricity Supply Industry in Transition, Bangkok, January 2004.

B. Kirby and E. Hirst, *Ancillary Service Details: Voltage Control*, ORNL/CON-453, Oak Ridge National Laboratory, Oak Ridge, Tenn., December 1997.

Laurence D. Kirsch and Harry Singh, "Pricing Ancillary Electric Power Services," *The Electricity Journal*, Vol. 8, No. 8. pp. 28-36, October 1995.

J. W. Lamont and J. Fu, "Cost Analysis of Reactive Power Support," *IEEE Transactions on Power Systems,* Vol.14, No.3, pp. 890-898, August 1999.

Ching-Yin Lee, Nanming Chen, "Distribution Factors of Reactive Power Flow in Transmission Line and Transformer Outage Studies." *IEEE Transactions of Power Systems*, Vol. 7, No. 1, pp. 194-200, February 1992.

Y. Z. Li and A. K. David, "Wheeling Rates of Reactive Power Flow Under Marginal Cost Pricing," IEEE Transactions on Power Systems. Vol.9, No.3, pp.1263-1269, August 1994.

P. Sakis Meliopoulos, Murad A. Asa'd and G. J. Cokkinides, "Issues for Reactive Power and Voltage Control Pricing in a Deregulated Environment," *Proceedings of the 32nd Hawaii International Conference on System Sciences – 1999.*

A. Murdoch, G.E. Boukarim, B.E. Gott, M.J. D'Antonio and R.A. Lawson, "Generator Over Excitation Capability and Excitation System Limiters," IEEE/PES 2001.

P. Nedwick, A.F. Mistr, Jr., and E.B. Croasdale, "Reactive Management: A Key to Survival in the 1990s," *IEEE Transactions on Power Systems*, Vol.10, No. 2, pp. 1036-1043, May 1995.

Emilia Nobile and Anjan Bose, "A New Scheme for Voltage Control in a Competitive Ancillary Service Market," 14th PSCC, Sevilla, Session 20, Paper 4, June 2002.

H. R. Outhred and F. C. Schweppe, "Quality of Supply Pricing for Electric Power Systems," IEEE Power Engineering Society Winter Meeting, New York, February 3–8, 1980.

PJM, Reactive Services Working Group Report, September 29, 2001.

Peter W. Sauer, Thomas Overbye, George Gross, Fernando Alvarado, Schmuel Oren and James Momoh, "Reactive Power Support Services in Electricity Markets: Costing and Pricing of Ancillary Services Project Final Report." Power Systems Engineering Research Center (PSERC) Publication 00-08, May 2001.

Peter W. Sauer, "What is Reactive Power?" Power Systems Engineering Research Center, Department of Electrical and Computer

Engineering, University of Illinois at Urbana-Champaign, September 16, 2003.

F.C. Schweppe, M.C. Caramanis, R.D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity*, Boston: Kluwer Academic Publishers, 1987.

Shams N. Siddiqi and Martin L. Baughman, "Reliability Differentiated Pricing of Spinning Reserve," *IEEE Transactions on Power Systems*, Vol. 10, No. 3, pp.1211-1218, August 1995.

James D. Weber, Thomas J. Overbye, Peter W. Sauer, and Christopher L. DeMarco, "A Simulation Based Approach to Pricing Reactive Power," *Proceedings of the Hawaii International Conference On System Sciences*, January 6-9, 1998, Kona, Hawaii, www.pserc.wisc.edu.

Antonio C. Zambroni de Souza, Fernando Alvarado and Mevludin Glavic, "The Effect of Loading on Reactive Market Power," *Proceedings of the 34th Hawaii International Conference on System Sciences,* 2001.

An Engineering and Economic Analysis of Real and Reactive Power from Synchronous Generators

In this appendix, we will start a discussion to explore future pricing of reactive power from generation. We examine the incentives for efficient investment and operations decisions through price and quantity signals from the system operator to synchronous generators. We examine the generator operator (GO) as a price taker avoiding the complications of gaming strategies, and, thereby, we ignore market power issues here because they complicate the discussion and can be addressed through mitigation. We focus on the cost and profits of producing real and reactive power from synchronous generators. The analysis focuses on steady-state operations with minor and temporary excursions into disequilibrium. A more complete discussion must include a full discussion of reliability in general and transient and dynamic stability in particular. The analysis for motors, the consumers of real and reactive power, is essentially the same. For simplicity of exposition we simplify the representation of some other characteristics and products.

A generator can be viewed as a multiproduct firm. Among the joint products that the generator offers are real power, real power reserves, reactive power and reactive power reserves. The investment and operating decisions are made based on market rules and expected revenues from the products it sells. The life of a generator starts with the investment decision. The decision to build a generator occurs if the expected discounted revenues from all services exceed the costs including a risk adjusted return on investment. There are many design decisions that determine the costs of building and operating the generator. In turn the market design and design decisions determine the revenues streams. Here we will pay special attention to the reactive power design capabilities, but they are intimately intertwined with the overall design.

In these appendices the approach taken is indifferent to whether the system operator is independent or a vertically integrated utility. If the system operator is independent, it must monitor and mitigate market power and the asset owner/operators have a greater incentive to be efficient. If the system operator is a vertically integrated utility, the prices become transfer prices for internal transactions and the efficiency incentives are usually blunted by the overall regulatory scheme.

Currently, most generators are given schedules that include the quantity of real power produced, a voltage and a range in which each must be kept to avoid incurring financial penalties. Some system operators send prices along with the real power and voltage. Occasionally, the system operator asks for additional amounts of reactive power. Schedules may be set daily, but may vary in intervals of minutes or seconds. Most equipment has automatic controls to maintain the prescribed ranges.

The Investment Decision. Generator investment decisions determine its range of operation and are driven by technology, interconnection rules, market rules, the market design and the prices that result. The preference is that the generator design be the result of efficient market signals. Many parameters describe the generator. For example, more expensive cooling equipment allows higher levels of sustained reactive power output before serious equipment damage. An incentive for this can come from a price signal for reactive power. To describe the investment decision we start by defining some of the design parameters. Let

P^{min}, P^{max} be the minimum and maximum rated real power output, respectively, in MW Q^{min}, Q^{max} be the minimum and maximum rated reactive power output, respectively, in Mvar (the same units as MW), Prr^{max} be the maximum rated ramp rate for real power output, in MW/sec, Qrr^{max} be the maximum rated ramp rate for reactive power output, in MW/sec, HR be the heat rate in MMBtu/MWh.

We will assume the ramp rates up and down are equal and the heat rate is uniform over the operating range. The capital costs are:

$$C(P^{min}, P^{max}, Q^{min}, Q^{max}, Prr^{max}, Qrr^{max}, HR).$$

In general, as P^{max} increases, C increases ($\partial C/\partial P^{max} = C' > 0$), but the average capital costs (C/P^{max}) decline then eventually increase with increasing P^{max}. Differentiating average costs with respect to P^{max}:

$$\partial(C/P^{max})/\partial P^{max} = (\partial C/\partial P^{max})/P^{max} - C/(P^{max})^2 = (P^{max}\ \partial C/\partial P^{max} - C)/(P^{max})^2.$$

Average capital costs reaches its minimum at a capacity $P^{max} = P^{max*}$ satisfying $\partial(C/P^{max})/\partial P^{max} = 0$ or

$$\partial C/\partial P^{max} = C'(P^{max*}) = C(P^{max*})/P^{max*}$$

That is, for P^{max} up to P^{max*}, $C' > C/P^{max}$ while, for $P^{max} > P^{max*}$, the average costs increase with increasing P^{max}.

Also, as Q^{max} increases, C increases ($\partial C/\partial Q^{max} > 0$), but the average capital costs (C/Q^{max}) decline with increasing Q^{max} up to some level Q^{max*} where the average costs increase with increasing Q^{max}. For practical purposes, Qrr^{max} is generally large enough that it is almost never a binding constraint and is not a significant component of capital costs. Thus, we will drop it from further analysis.

The turbine is often designed to the smallest P^{min} possible. For a steam boiler, P^{min} will most likely be determined by steam operating constraints. A high value of P^{min} makes the generator

less flexible, results in high start-up and no-load costs and, therefore, less valuable as an asset. Q^{min} and Q^{max} are determined by the overall design and the cooling equipment in the generator. Prr^{max} is limited by thermal and mechanical stress and stability. For fossil fuel generators since the fuel costs are a large part of total costs and the expected asset life of 20 years or more, the heat rate (HR) is usually designed to the most efficient technology. In the past 20 years the heat rate for gas generators has improved from 12,000 to 6,000 MMBtu/MWh. Over the life of the generator these characteristics can change, as components are replaced and upgraded with new equipment. For example, when a turbine is replaced the real power capability can increase, changing the operating characteristics.

In designing generating plants, for a given turbine size, the other equipment (the exciter, alternator, voltage regulator, step-up transformer) can be sized larger for greater production of reactive power when at the same real power output. If the other equipment is fixed, the turbine can be sized or resized in an overhaul, moving the turbine constraint closer to the boundary of the generator's D-curve, discussed in more detail later in this appendix. The market design compensation scheme will, in part, determine the future configuration of IPP generators.

One approach to determining these cost differences is to ask for bids or "quotes" for different levels of capability from the manufacturer. Instead of formal quotes, the choice of parameters is often achieved through discussion and negotiation with the equipment vendors.

The investment decision requires revenue forecasts from a portfolio of contracts and projected spot market profits. The decision becomes to invest if:

$$C(P^{min}, P^{max}, Q^{min}, Q^{max}, Prr^{max}, Qrr^{max}, HR) < \sum_t d_t[\pi_t(p_t, P_t, Q_t) + CP_t]$$

where d_t is the discount factor, p_t is a vector of the expected market prices after entry, P_t, Q_t are vector of the expected market quantities after entry (Lower case p denotes a price and upper case P denotes real power.), π_t are the spot market profits for period t and CP_t are the contract payments net of spot market revenues in period t.

Contract payments can be from sale of future output commitments and/or rate base demand charges.

Although not necessarily required, central forward markets can create contractual commitments to supply reserves of both real and reactive power that minimizes the costs of maintaining reliability. With mobile technologies, entry decisions have shorter time horizons. Some devices can be installed and relocated in less than a year. Other technologies can be installed within an auction with a longer time horizon of the procurement. Market participants could offer equipment without a precommitment of installation. Reserves markets can be characterized as stochastic variations of optimal dispatch auctions.

In competitive markets, generators are designed through parameter choices to maximize total profits equal to operating profits plus contract payments minus capital costs:

$$\text{Max } \sum_t d_t[\pi_t(p_t, P_t, Q_t) + CP_t] - C(P^{min}, P^{max}, Q^{min}, Q^{max}, Prr^{max}, Qrr^{max}, HR).$$

When risk and uncertainty are introduced, a more complex stochastic analysis involving real options is necessary, but this topic is beyond the scope of this appendix.

Over time, generator design and manufacturing will move to the most profitable design. If the market design omits paying for certain desirable characteristics, such as reactive power, they will tend to be undersupplied. When these decisions result in sunk capital, we may have to live with them for years or decades. In efficient competitive markets, the most profitable design will be the design most beneficial to society, within the framework of the market rules.

Operating Constraints. The economic operation of a generator requires that it operate within certain constraints to avoid outages and serious equipment damage. These constraints are determined by the physical design of the generator, the materials it is made of, the size of the components, etc. The input to a synchronous generator is an energy source, e.g., hot gasses, air, steam or water that turns a turbine.

Synchronous generators supply complex power. Power entering the network from a synchronous generator has real and reactive power components. We start with a voltage source **E** (complex numbers are bold and real numbers are in light face type):

$$\mathbf{E} = \mathbf{Z_G I} + \mathbf{V}$$

where **E** is the internal generated voltage of the machine, $\mathbf{Z_G} = R + (-1)^{1/2}X_d$, R is the resistance, X_d is the synchronous reactance, **I** is the complex current (**I*** is the complex conjugate of **I**, i.e., $\mathbf{I(I^*/|I|^2)} = 1$),and **V** is the complex voltage.

The complex power from the generator is:

$$\mathbf{S = VI^* = V(E-V)^*/Z_G^*}$$

Since R is usually much smaller than X_d, we can assume R = 0, then

$$P = VE\sin(\delta)/X_d$$

$$Q = V(E\cos(\delta) - V)/X_d$$

where δ is the torque angle of the machine equal to the difference in phase angle between **E** and **V**, P is the real power output of the generator and Q is the reactive power output of the generator,

Since $\sin^2(\delta) + \cos^2(\delta) = 1$,

$$(PX_d / VE)^2 + ((Q\,X_d + V^2)/VE)^2 = 1 \text{ or}$$

$$P^2 + (Q + V^2/X_d)^2 = (VE/X_d)^2$$

If the maximum design capability of the field current equipment occurs at E^{max} then the field current constraint of the D-curve becomes:

$$P^2 + (Q + V^2/X_d)^2 \leq (VE^{max}/X_d)^2$$

When additional real power is needed, the steam valve (for a steam turbine) is opened, the torque increases, the rotor speeds up and the frequency increases. This increase in real power must be met by an increase in load or decrease in other generation in order to keep the frequency in an acceptable range, and supply and demand on the system in balance. If V, E, X_d remain constant, the power angle must be increased and Q will decrease.

If the voltage regulator setting is increased, E increases. If V, δ, X_d remain constant, the Q will increase. If voltage and reactance are held constant,

$$\partial P/\partial E = V\sin(\delta)/X_d$$

$$\partial Q/\partial E = V\cos(\delta)/X_d$$

Operating Costs. We will assume that in the time period t fuel costs are constant. The operating costs in time period t are

$$c_t(P_t, Q_t, PR^{dwn}, PR^{up}, QR^{dwn}, QR^{up}; P^{min}, P^{max}, Q^{min}, Q^{max}, Prr^{max}, HR, c_{ft}, q_{ft}, c_{sup}) = c_{ft}q_{ft} + c_{sup}$$

where c_{ft} is the fuel and variable O&M costs in \$/fuel unit q_{ft} is the quantity of fuel in fuel units, c_{sup} is the unit start-up costs, if the generator is running, $c_{sup} = 0$. P_t is the real power output of the generator, PR^{dwn} and PR^{up} are real power reserves in the up and down directions, Q_t is the reactive power output of the generator, QR^{dwn} and QR^{up} are reactive power reserves in the up and down directions.

The quality of real power reserves is often specified in terms of the ramp rate constraints. For example, the maximum change in real power output by a generator in ten minutes is the

maximum ten-minute reserve quantity. Comparable ramp rates for reactive power are effectively unlimited.

Dropping the fixed parameters to simplify, and defining losses as $\ell(P_t, Q_t)$:

$$c_t(P_t, Q_t, PR^{dwn}, PR^{up}, QR^{dwn}, QR^{up}) = c_{ft}q_{ft} + c_{sup}$$

Subject to the production possibilities set defined as

Fuel input
$$P_t \leq q_{ft}/HR - \ell(P_t, Q_t) \qquad \lambda_{MW} \qquad (1)$$

Real power capacity
$$P^{min} + PR^{dwn} \leq P_t \leq P^{max} - PR^{up} \qquad \lambda_{Pmin}, \lambda_{Pmax}$$
$$\qquad (2, 3)$$

Reactive power capacity
$$Q^{min} + QR^{dwn} \leq Q_t \leq Q^{max} - QR^{up} \qquad \lambda_{Qmin}, \lambda_{Qmax}$$
$$\qquad (4, 5)$$

Ramp rate
$$P_t \leq P_{t-1} \pm Prr^{max} \qquad \lambda_{PRD}, \lambda_{PRU} \qquad (6, 7)$$

rotor/field current
$$(P_t - P_f)^2 + (Q_t - Q_f)^2 \leq (S_f)^2 \qquad \lambda_f \qquad (8)$$

stator/armature current
$$(P_t)^2 + (Q_t)^2 \leq (S_a)^2 \qquad \lambda_a \qquad (9)$$

under excitation/armature core end
$$(P_t - P_u)^2 + (Q_t - Q_u)^2 \leq (S_u)^2 \qquad \lambda_u \qquad (10)$$

Miscellaneous
$$Q_t \leq b_i P_t + a_i \quad \lambda_i \text{ for } i = 11, \ldots, n$$
$$\qquad (11, \ldots n)$$

where (P_i, Q_i) is the center of a circle with radius S_i for $i = f, u, \lambda_{MW}$ is the marginal value of the thermal power input to the generator, losses are $\ell(P_t, Q_t) = f(I_f^2 R_f, I_a^2 R_a)$, $\lambda = (\lambda_{MW}, \lambda_{Pmin}, \lambda_{Pmax}, \lambda_{Qmin}, \lambda_{Qmax}, \lambda_{PRD}, \lambda_{PRU}, \lambda_f, \lambda_a, \lambda_u, \lambda_{11}, \ldots, \lambda_n)$ is a vector of marginal values (dual variables or Lagrange multipliers).

The last set of constraints is a catch-all category that includes the stability limit of the voltage regulator, voltage limits, generator terminal voltage limits and the prime mover operating limits. They can be reasonably approximated by linear inequalities. (See reference [1].)

Power Input. Equation (1) is the thermal power conversion equation for complex power. It can be approximated by a set of piecewise linear constraints represented by chords of the circle.

Losses. Losses result from currents occuring in several circuits, all of which increase fuel consumption and wear on the generator. The rotor field current losses are $I_f^2 R_f$; the stator field current losses are $I_a^2 R_a$. The heating induced by $I^2 R$ increases the temperature in the wires. High temperatures over sustained periods can cause equipment damage, but can be reduced with additional cooling in the generator. Other losses from eddy currents and friction are usually ignored in steady-state models; however, they are often significant in the damping constants for dynamic models.

Operating Reserves. An operating reserve is capacity held off the market to respond to one or more system contingencies. Operating reserves should be determined and priced simultaneously in auctions or power systems optimizations. Reserves capability is mostly determined by investment decisions and can be procured in forward markets, if necessary. Since, in this section of the appendix, we are not focusing on reserves, for ease of presentation, we will incorporate reserves into P^{min}, P^{max}, Q^{min}, and Q^{max}. The cost function now becomes $c_t(P_t, Q_t)$, and the constraints in equations (2, 3) and (4, 5) become $P^{min} \leq P_t \leq P^{max}$, and $Q^{min} \leq Q_t \leq Q^{max}$, respectively.

Efficient Operations. Efficient operations require that the generator produce the optimal output at least cost. This is true for both a vertically integrated utility and ISO markets. In a vertically integrated utility, the dual variables or Lagrange multipliers from the optimal power flow model are equivalent to the market clearing prices from the ISO. The operating or spot market profits in time period t are

$$\pi_t(p_t, P_t, Q_t,) = p_{Pt}P_t + p_{Qt}Q_t - c_t(P_t, Q_t)$$

where p_{Pt} is the price of real power, and p_{Qt} is the price of reactive power.

Lower case p denotes a price and upper case P denotes real power.

In normal operations P is positive, but Q can be both positive and negative. A negative price signals the need for negative amounts (absorption) of reactive power. The resulting revenues, $p_{Qt}Q$, are nonnegative.

The D-curve. The constraints, (8), (9) and (10), form the D-curve, or generation capability curve, that partially defines the boundary of the PQ possibilities set. Respecting these constraints prevents damage from overheating, but they can be violated for short periods of time without significant damage. This allows for fast adjustments in reactive power output. The field current constraint is centered at $(0, -V^2/X_d)$ where X_d is the direct axis synchronous reactance with radius VE_{max}/X_d. They can be conservatively represented by the chords on the circles at the intersection points as follows and shown in Figure B1:

Figure B1. **Linear Approximations of the Generator Capability Curve**
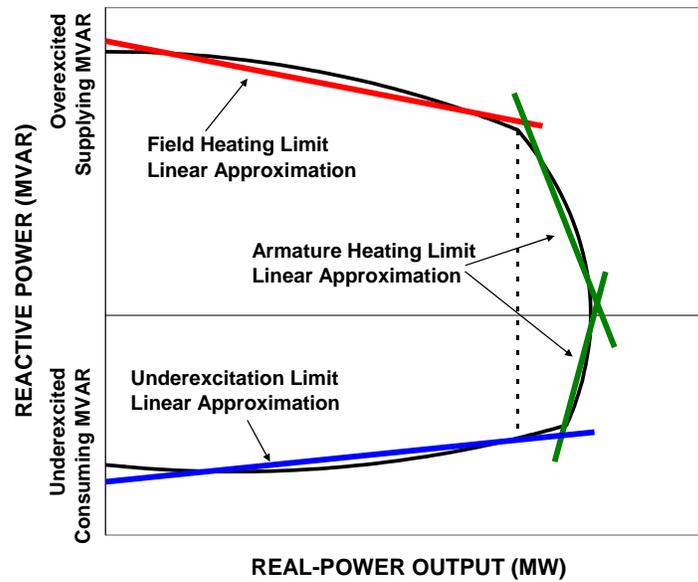
Source: Modified from B. Kirby and E. Hirst 1997, Ancillary-Service Details: VoltageControl,
ORNL/CON-453, Oak Ridge National Laboratory, Oak Ridge, Tenn., December 1997.

linear approximation to the field current constraint: $Q_t \leq b_f P_t + a_f$

linear approximation to the armature current constraint: $Q_t \leq b_a P_t + a_a$

linear approximation to the under excitation constraint: $Q_t \leq b_u P_t + a_u$

If a generator is operating on the turbine constraint, the marginal cost of producing reactive power is essentially zero. When a generator is not on the turbine constraint and is on another constraint, the locational price of reactive power is the opportunity cost of backing down real power. The b coefficients define the tradeoff between real and reactive power on the boundary of the constraint set and

$$\frac{\partial Q_t}{\partial P_t} = \begin{pmatrix} 0, \text{ if not on the boundary} \\ b_f, \text{ if field current constraint is binding} \\ b_a, \text{ if armature current constraint is binding} \\ b_u, \text{ if under excitation constraint is binding} \end{pmatrix}$$

The slope b_f is typically about -.7, b_a is typically about -5 and b_u is typically about .4. When operating inside the D-curve, the marginal cost of producing reactive power is essentially zero or, more precisely, related to the marginal cost of losses in the generator. On the armature constraint, large increases of reactive power are available for very little decrease in real power defined on a unit basis by b_f. (The armature constraint could be split in two linear constraints, each terminating at $Q_t = 0$.) On the field current constraint, reactive power can be increased by a unit by decreasing real power by b_a. On the under excitation constraint, reactive power can be increased by a unit by decreasing real power by b_u. There is often a constraint for a voltage regulator with a slope of about .1.

If the windings have additional cooling capability, the parameters of the D-curve become variable. Assuming the b parameters are constant, the first order approximation is

a_i = f(cooling temperature in the windings), a is a vector of a_i's and

$c_i(a_i)$ is the costs of changing a_i.

Therefore, the cost of adjusting the D-curve constraints is $c_i(a_i)$.

Soft Constraints. In emergencies, equipment may be operated beyond rated, nominal or steady-state limits for short periods of time. As formulated, the production possibilities set is composed of 'hard' constraints. To 'soften' the constraint, let P^{maxr} be the rated capacity and make P^{max} a variable with the following entry in the cost function:

$c_P(P^{max})$ is proportional to $(P^{max}/P^{maxr})^m$

For m large, $c_P(P^{max})$ is close to 0 when $0 < P^{max} < P^{maxr}$ and $c_P(P^{max})$ increases quickly when P^{max} becomes larger than P^{maxr}. The function, $c_P(P^{max})$, can be much more detailed, but for this discussion the simple polynomial will suffice. This can be closely approximated by a piecewise linear function.

Taking into account operating reserve simplifications, variable cooling and soft constraints, the cost function becomes

$c(P_t, Q_t, a_i, P^{max}) = c(P_t, Q_t) + \sum_i c_i(a_i) + c_P(P^{max})$.

This cost function has been described as a 'hockey stick' curve because it is very steep beyond P^{maxr} and as a_i gets large. A similar 'penalty' approach can be used to soften other constraints.

Profit Maximization or Cost Minimization. For time period t, given prices, p, (we drop the subscript, t, to ease the presentation) and remembering that we are ignoring reserves, to maximize profits, we form the Lagrangean:

$$L(P, Q, u, \lambda) = p(P, Q) - c(P, Q, u) - \lambda_{MW}(P - q_f/HR + \ell(P, Q)) - \lambda K(P, Q, u)$$

where u is a vector of control or decision variables, e.g., a, P^{max}, and q_f, and $K(P, Q, u) \leq 0$ is the linearized production possibilities set defined by:

$$P^{min} \leq P \leq P^{max}$$
$$Q^{min} \leq Q \leq Q^{max}$$
$$P \leq P_{-1} \pm Prr^{max}$$
$$Q \leq b_iP + a_i \quad \text{for } i = 8,\ldots, n$$

where P_{-1} is previous period real output.

$$\lambda = (\lambda_{Pmin}, \lambda_{Pmax}, \lambda_{Qmin}, \lambda_{Qmax}, \lambda_{PRD}, \lambda_{PRU}, \lambda_8, \ldots, \lambda_n)$$

$$\lambda_{MW}, \lambda \geq 0.$$

The generator maximizes profits by maximizing its Lagrangean. The optimality conditions include

$$\partial L/\partial q_f = -c_f + \lambda_{MW}/HR = 0 \text{ or } \lambda_{MW} = c_fHR.$$

The value of an additional MW is the heat rate times the cost of fuel.

For optimal real power,

$$\partial L/\partial P = p_P - \lambda_{MW}(1 + \partial\ell/\partial P) + \lambda_{Pmin} - \lambda_{Pmax} + \lambda_{PRD} - \lambda_{PRU} + \sum_i \lambda_ib_i = 0.$$

Solving for p_P, the component parts of the real power price are:

$$p_P = \lambda_{MW}(1 + \partial\ell/\partial P) - \lambda_{Pmin} + \lambda_{Pmax} - \lambda_{PRD} + \lambda_{PRU} - \sum_i \lambda_ib_i$$

When the generator operates at capacity and is not being used for reserves or on the D boundaries,

---

$$p_P = \lambda_{MW}(1 + \partial\ell/\partial P) + \lambda_{Pmax} = c_f HR(1 + \partial\ell/\partial P) + \lambda_{Pmax}$$

The price is a composite of the fuel cost, heat rate losses and the value of additional capacity.

If a constraint in $K(P, Q, u) \leq 0$ is not binding, the associated λ_i is 0. Except under unusual conditions, only one or two of the λ's are nonzero. For λ_{Pmin} and λ_{Pmax}, both cannot simultaneously be greater than 0. For λ_{PRD} and λ_{PRU}, both cannot simultaneously be greater than 0.

Similarly, for optimal reactive power,

$$\partial L/\partial Q = p_Q - \lambda_{MW}\partial\ell/\partial Q + \lambda_{Qmin} - \lambda_{Qmax} + \lambda_{QRD} - \lambda_{QRU} + \sum_i \lambda_i b_i = 0$$

Solving for p_Q, the component parts of the reactive power price are:

$$p_Q = \lambda_{MW}\partial\ell/\partial Q - \lambda_{Qmin} + \lambda_{Qmax} - \lambda_{QRD} + \lambda_{QRU} - \sum_i \lambda_i$$

When the generator is not being used for reserves or on the D-curve boundaries, the price is a function of the losses and the price for reserves:

$$p_Q = \lambda_{MW}\partial\ell/\partial Q - \lambda_{QRD} + \lambda_{QRU}$$

Except under unusual conditions, only one or two of the λ's are nonzero. For λ_{Qmin} and λ_{Qmax}, both cannot simultaneously be greater than 0. For λ_{QRD} and λ_{QRU}, both cannot simultaneously be greater than 0.

Prices can be positive or negative. For generators, the real power price is (almost always) positive, but the reactive power can be positive or negative. When p_Q is negative and Q is negative, the payment is positive: the generator is being paid to absorb reactive power to hold voltage down. This might occur in light loading conditions if the transmission lines and capacitors could not be switched out to reduce reactive power production elsewhere.

If output (P, Q) is not on the boundary of the augmented (variably cooled) 'D - curve' then $\lambda_i = 0$, i = 8,…, n. If (P, Q) is on the boundary then typically only one λ_i can be greater than 0. But the boundary can be moved at a cost and

$$\partial L/\partial a_i = \partial c_i(a_i)/\partial a_i - \lambda_i = 0, \quad \text{for } i = 1, …, n.$$

$$\partial L/\partial P^{max} = m((P^{max})^{m-1}/(P^{maxr})^m) - \lambda_{Pmax} = 0.$$

To simplify the analysis of the real/reactive tradeoffs, we will assume that the first eight constraints of K(P, Q, u) ≤ 0 are not binding, then

$$\lambda_{Pmin} = \lambda_{Pmax} = \lambda_{Qmin} = \lambda_{Qmax} = \lambda_{PRD} = \lambda_{PRU} = 0$$

If output (P,Q) is not on the boundary of the D-curve,

$$p_P = \lambda_{MW}(1 + \partial\ell/\partial P)$$

$$p_Q = \lambda_{MW}\partial\ell/\partial Q$$

If one $\lambda_i > 0$, i = 1,...,n

$$p_P = \lambda_{MW}(1 + \partial\ell/\partial P) - \lambda_i b_i$$

$$p_Q = \lambda_{MW}\partial\ell/\partial Q + \lambda_i$$

System Dispatch. In an ISO market or vertically integrated utility, a generator sends a bid or cost function in the form of the cost function along with its operating constraints. Also, the generator must run or spin at the system frequency (60 cycles per seconds in North America). The SO also requires generation, load and transmission operators to operate to maintain bus voltages within a certain range. This is often called the dead band or zone. The system operator (SO) optimizes the system and returns one of the following signals to the generator, (P, V), (p_P, P, V) or (P, V, Q), depending on the market design.

Using p_Q as the signal for Q can be ambiguous because a large range of reactive power can often be produced at a cost close to zero. Therefore, a (p_P, p_Q) signal is generally unacceptable and should have quantities associated with the prices of reactive power. There are often penalties for operating outside the prescribed quantity range; in an ISO this penalty is often a function of the bus or nodal price. A safe but possibly redundant signal would be (P, V, Q, p_P, p_Q) where (P, V, Q) should be an optimal solution to the generator's bid function.

Multipart Contracts or Tariffs. If investments are lumpy and cost recovery or profitability in the spot markets is risky, multipart tariffs or contracts may be employed to lower risk and address lumpy investments. An efficient multipart tariff requires one or more demand charges for capacity that recovers capital costs not recovered in the spot market. The demand charge can be considered a real option payment to ensure the capability is available when needed. Because investment in reactive power is a joint cost with real power capacity, the proper demand charge for reactive power is hard to establish. This is particularly difficult when real power is compensated through market prices. When compensation for reactive power capacity is properly recovered, the commodity rate of opportunity costs would be compensatory.

Opportunity Costs. Let (P_1, Q_1) be the dispatch at the required level of reactive power and p_{P1} is the price of real power under the dispatch. Also, let (P_2, Q_2) be the dispatch after a redispatch beyond the required level of reactive power and p_{P2} is what the price of real power with the redispatch.

$$\text{Profits}_1 = p_{P1}P_1 - c(P_1,Q_1)$$

$$\text{Profits}_2 = p_{P2}P_2 - c(P_2,Q_2)$$

$$\text{Opportunity costs} = \text{Profits}_2 - \text{Profits}_1 = p_{P2}P_2 - c(P_2,Q_2) - (p_{P1}P_1 - c(P_1,Q_1))$$

If $b(P,Q)$ is the bid function,

$$\text{Apparent opportunity costs} = p_{P2}P_2 - b(P_2,Q_2) - (p_{P1}P_1 - b(P_1,Q_1))$$

If the generator must dispatch real power down, in order to meet reactive power requirements, then $P_2 < P_1$, usually $p_{P2} > p_{P1}$ and $b(P_2,Q_2) < b(P_1,Q_1)$. Apparent opportunity costs are necessarily usually positive.

Summary. This appendix examined the investment and operating decisions of generation market participants with particular focus on reactive power and the trade-offs with real power. it also has laid the ground for bidding in the auctions in Appendix D.

References:

1. M. M. Adibi, "Reactive Power Consideration," Electric Power Research Institute, 2000.

2. Arthur R. Bergen and Vijay Vittal, *Power System Analysis*, 2nd Ed., Prentice Hall, 2000.

3. Charles A. Gross, *Power System Analysis*, Wiley, New York, 1979.

4. David Luenberger, *Optimization by Vector Space Methods*, Wiley, New York, 1969.

5. Oliv Mangasarian, *Nonlinear Programming*, McGraw-Hill, New York, 1969.

An Engineering and Economic Analysis of Real and Reactive Power from Transmission Elements

In this appendix, we examine the investment and operating decisions of a transmission owner/operator (TO) based on the cost of supplying and consuming real and reactive power from transmission elements in a market with active transmission participation. Currently, TOs do not participate in electricity markets in the way generators or loads do because they are not in a position to modify the operation of their equipment based on economic signals or prices. Exposing TOs to price signals could result in improved capital investment decisions, as well as operating decisions which could improve the performance of the entire grid. Transmission elements include lines, capacitors, reactors, FACTS devices and transformers. The TO can operate a single transmission element or a traditional control area. Here, we examine the TO's incentives to invest in, supply, transport and consume real and reactive power in a reliable and efficient manner when they play an active role in the market.

The TO may be different from the system operator. If the system operator is financially independent from the owners of the electric assets, it is called an Independent System Operator (ISO). In this appendix, the approach taken is indifferent to whether the system operator is independent or a vertically integrated utility. If the system operator is independent, it must operate under a market design that gives incentives to the asset owner/operators to be efficient. If the system operator is a vertically integrated utility, the prices become transfer prices for internal transactions with efficiency incentives blunted by the overall regulatory scheme. We examine the TO as an entity or function separate from the system operator.

We examine the TO as a price taker, avoiding the complications of gaming strategies. Gaming strategies are dampened through competition and mitigation of market power in the system operator's auction markets. The TO takes signals from the system operator and its investments in transmission assets are determined by profits (or the return on the investment).

The TO operates a transmission system by connecting and disconnecting transmission elements to and from the network, and by changing the phase angle, transformer tap setting, capacitance, inductance, resistance and impedance. Modern technical equipment can change some parameter settings in less than a cycle (i.e., less than 1/60 of a second) or so and can sustain repeated changes over successive cycles, but at additional capital and operating costs compared to conventional mechanical switching, which typically takes several cycles or more to operate and cannot sustain multiple successive changes.

Transmission elements can, in principle, compete under the market design to transport power first by designing and, after construction, changing the physical properties of the transmission elements to perform a more valuable service. If there is a price difference between

nodes, there usually are adjustments that can be made to improve efficiency. For example, by changing the resistance, reactance or capacitance of the transmission element the amount of real and reactive power flowing on the element can be changed to improve efficiency and reliability. These changes typically require expenditure and, consequently, the fundamental goal is to set incentives so that efficient changes are made, both in operations and in capital investments.

The analysis focuses on steady-state operations with minor and temporary excursions into disequilibrium. For simplicity of exposition we simplify the representation of some characteristics.

Active Transmission Market Participants. Today, in most ISO spot markets, transmission owners are mostly economically passive. That is, they usually do not change their device parameters in response to short-term economic conditions. The lack of active transmission market participation dulls the incentives of transmission owners for optimal investment and degrades potential system performance. Active transmission market participants subject to equipment, reliability and economic constraints should be a part of optimal system operation.

There are some current practices that treat transmission elements as not completely static. Today some capacitors are switched in and out by the TO on instructions from the system operator. Some equipment can be truck mounted and is therefore mobile. In light load, transmission lines are opened to better balance reactive power. In some markets, phase shifters are optimally dispatched in the day-ahead market; in others they are set as a result of a political debate or in near-emergency conditions. These examples illustrate a slow movement toward incorporating active transmission participation in electricity markets, but there are still many more opportunities for transmission participation that could be available through active market participation.

Investment Decisions. The carrying capacity of transmission lines is based on thermal, voltage and stability limits. These limits include surviving large disturbances or contingencies. Short lines (less than 50 miles) are usually limited by thermal capacity. Intermediate length lines (50 to 200 miles) are often voltage limited. Longer lines are often stability limited. Steady state stability limits are specified by the maximum allowed phase angle differences.

To examine the investment decision for a transmission element, we must describe the investment parameters. Let:

> MVA^{max} be the rated thermal capacity,
> τ be the transformer tap ratio, α be the transformer phase shift,
> R be the resistance, X be the reactance, and B_{cap} be the shunt susceptance.

> The capital costs of a transmission line are a function of these parameters:

> $C(MVA^{max}, R, X, Bcap, \alpha, \tau, length)$

In general, capital costs increase with MVA^{max} ($\partial C/\partial MVA^{max} > 0$), but the average capital costs per unit of rated thermal capacity (C/MVA^{max}) decline with increasing MVA^{max}. For higher capacity lines with operating voltages above 200 kV, the decline in average capital costs are small when all costs, including right-of-way and substation costs, are included. For additional information see reference [9].

Average capital costs may in some cases reach a minimum then increase. Differentiating average costs with respect to MVA^{max}:

$$\partial(C/MVA^{max})/\partial MVA^{max} = (\partial C/\partial MVA^{max})/MVA^{max} - C/(MVA^{max})^2$$

$$= (MVA^{max}\ \partial C/\partial MVA^{max}-C)/(MVA^{max})^2$$

$\partial(C/MVA^{max})/\partial MVA^{max}$ reaches its minimum at $MVA^{max} = MVA^{max*}$ satisfying $\partial(C/MVA^{max})/\partial MVA^{max} = 0$ or

$$\partial C/\partial MVA^{max} = C'(MVA^{max*}) = C(MVA^{max*})/MVA^{max*}$$

That is, where average costs equal marginal costs. For MVA^{max} up to MVA^{max*}, $C' < C/ MVA^{max}$ while for $MVA^{max} > MVA^{max*}$ the average costs increase with increasing MVA^{max}.

In general, capital costs also increase with decreasing resistance ($\partial C/\partial R < 0$). For very large capital expenditures like superconductors, resistance can be lowered to near zero with superconducting technology. However, with superconductors there is an energy expenditure to maintain the superconducting state, which is analogous to losses but with a different dependence on flow. In general, capital costs increase with decreasing impedance ($\partial C/\partial X < 0$). The ability to change transformer tap ratios or the existence of phase shifter settings add to the flexibility to respond to market signals. One approach to determining these cost differences is to ask for bids with different levels of capability.

The investment decision requires revenue forecasts from a portfolio of contracts and projected spot market profits. The decision is to invest if:

$$C(MVA^{max}, R, X, Bcap, \alpha, \tau, length) < \sum_t d_t[\pi_t(p_t, P_t, Q_t, TRM_t) + CP_t]$$

where d_t is the discount factor, p_t is a vector of the projected market prices after entry, (P_t, Q_t) are vector of the projected market quantities after entry (Lower case p denotes a price and upper case P denotes real power.), TRM_t is the transmission reliability margin in time period t that can be differentiated by direction, π_t are the spot market profits for period t and CP_t are the contract payments net of spot market revenues in period t. Contract payments can be from selling point-to-point transmission rights and flowgate rights and/or rate base demand charges.

Although not necessarily required, forward markets can create contractual commitments to supply reserves, both real and reactive. With mobile technologies, some devices can be installed

---

Principles for Efficient and Reliable Reactive Power Supply and Consumption

in less than a year or the time horizon of the procurement. Market participants could offer equipment without a precommitment of installation. Reserves markets can be characterized as stochastic variations of optimal dispatch auctions. This issue will be discussed in appendix D.

For profit oriented investors, transmission is designed to maximize total profits equal to operating profits plus contract payments minus capital costs:

$$\text{Max} \sum_t d_t[\pi_t(p_t, P_t, Q_t, TRM_t) + CP_t] - C(MVA^{max}, R, X, Bcap, \alpha, \tau, length).$$

When lumpiness, risk and uncertainty are introduced, a more discrete complex stochastic analysis involving real options is appropriate for a complete analysis, but this topic is beyond the scope of this appendix.

Over time, transmission asset design and manufacturing will move to the most profitable design. For example, more expensive better performing equipment will not be employed unless it is profitable. If the market design omits paying for certain desirable characteristics, they will tend to be undersupplied. Requiring certain characteristics without paying for them has poor incentives and could distort other markets. When these decisions result in sunk capital, we may have to live with them for years or decades. In efficient competitive markets, the most profitable design will be the design most beneficial to society, within the framework of the market rules. Next we examine profits and efficient operations in the short term markets.

Steady State Flow Equations for Transmission. The operation of an asset must obey the physical laws. We describe the operating constraints and the influence on parameter choice on output in this section. A generic transmission line can be defined in the Figure C1 below:

<p align="center">Figure C1: Generic Transmission Line</p>
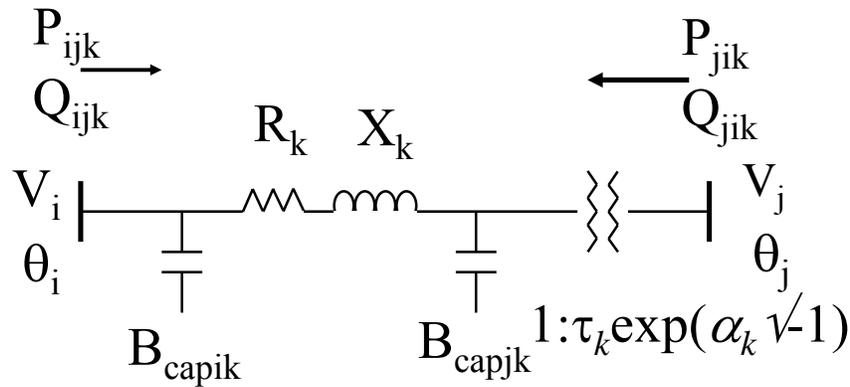
Shunt conductance in the model is omitted for clarity and since it is usually negligible. The basic equation for defining the real power flow along line k from bus $i = I(k)$ towards bus $j = J(k)$ is:

$$P_{ijk} = G_k[(V_i)^2 - (V_iV_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)] - B_k(V_iV_j/\tau_k)\sin(\theta_i - \theta_j + \alpha_k)$$

$$P_{jik} = G_k[(V_j/\tau_k)^2 - (V_iV_j/\tau_k)\cos(\theta_j - \theta_i - \alpha_k)] - B_k(V_iV_j/\tau_k)\sin(\theta_j - \theta_i - \alpha_k)$$

where:
θ_i is the phase angle of the voltage at bus i and $\theta_{ij} = \theta_i - \theta_j$
V_i is the voltage magnitude at bus i ($V_i = V_j/\tau_k + i_k(R_k + (-1)^{1/2}X_k)$),
τ_k is the ideal transformer tap ratio on line k
α_k is the ideal transformer phase shift on line k
G_k and B_k are line parameters determined by the resistance and reactance of the line k. The parameters G_k and B_k, called conductance and susceptance respectively, are determined from the resistance, R_k, and the reactance, X_k, of line k:
$G_k = R_k/(R_k^2 + X_k^2)$ and $B_k = -X_k/(R_k^2 + X_k^2)$.
I and J are index sets of the end buses for transmission element k. The end busses of line k are specified by the sets I and J.

To examine the contribution to profit, we need to examine the marginal performance of the equipment. To examine the transmission response to changes in control parameters, for ease of presentation, we will assume all functions are continuously differentiable. Discrete changes can be introduced with integer valued variables but it brings additional notational complexity which will be omitted here. For additional information see reference [4].

The partial derivatives of conductance and susceptance with respect to resistance and reactance are:

$$\partial B_k/\partial R_k = -\partial G_k/\partial X_k = 2R_kX_k/(R_k^2 + X_k^2)^2$$

$$\partial G_k/\partial R_k = \partial B_k/\partial X_k = (X_k^2 - R_k^2)/(R_k^2 + X_k^2)^2$$

Prior to investment the element parameter choices, particularly that of resistance, can be highly variable. Once the element is constructed the options for varying the parameters are more limited.

The partial derivatives of real power with respect to the phase angle and the voltage at bus i are:

$$\partial P_{ijk}/\partial\theta_{ij} = \partial P_{ijk}/\partial\alpha_k = (V_iV_j/\tau_k)(G_k\sin(\theta_{ij}+\alpha_k) - B_k\cos(\theta_{ij}+\alpha_k))$$

$$\partial P_{ijk}/\partial V_i = G_k(2V_i - (V_j/\tau_k)\cos(\theta_{ij} + \alpha_k)) - B_k(V_j/\tau_k)\sin(\theta_{ij}+ \alpha_k)).$$

The partial derivatives of real power with respect to conductance and susceptance are:

$$\partial P_{ijk}/\partial G_k = V_i^2 - (V_iV_j/t_k)\cos(\theta_{ij} + \alpha_k)$$

$$\partial P_{ijk}/\partial B_k = -(V_iV_j/t_k)\sin(\theta_{ij}+ \alpha_k).$$

For $-\pi/2 \leq \theta \leq \pi/2$, $-1 \leq \sin(\theta) \leq 1$ and $0 \leq \cos(\theta) \leq 1$. Since $\cos(\theta_{ij} + \alpha_k) < 1$, if $V_i > V_j/t_k$ then $\partial P_{ijk}/\partial G_k > 0$. If $\sin(\theta_{ij}+ \alpha_k) > 0$ then $\partial P_{ijk}/\partial B_k < 0$. If $\sin(\theta_{ij}+ \alpha_k) < 0$ then $\partial P_{ijk}/\partial B_k > 0$.

The partial derivatives of real power with respect to resistance and reactance are:

$$\partial P_{ijk}/\partial R_k = (\partial P_{ijk}/\partial G_k)(\partial G_k/\partial R_k) + (\partial P_{ijk}/\partial B_k)(\partial B_k/\partial R_k) =$$

$$[(X_k^2 - R_k^2)(V_i^2 - (V_iV_j/\tau_k)\cos(\theta_{ij} + \alpha_k)) - 2R_kX_k(V_iV_j/\tau_k)\sin(\theta_{ij}+ \alpha_k)]/(R_k^2 + X_k^2)^2.$$

$$\partial P_{ijk}/\partial X_k = (\partial P_{ijk}/\partial G_k)(\partial G_k/\partial X_k) + (\partial P_{ijk}/\partial B_k)(\partial B_k/\partial X_k) =$$

$$[-2R_kX_k(V_i^2 - (V_iV_j/\tau_k)\cos(\theta_{ij} + \alpha_k)) - (X_k^2 - R_k^2)(V_iV_j/\tau_k)\sin(\theta_{ij}+ \alpha_k))]/(R_k^2 + X_k^2)^2$$

Since $\partial P_{ijk}/\partial G_k > 0$, if $R_k << X_k$ then $\partial P_{ijk}/\partial R_k > 0$, but the increase in flow due to an increase in R_k is accounted almost entirely by an increase in losses; that is, delivered power decreases with increasing R_k. (See the expression for partial derivative of losses, below.)

We often make simplifying assumptions to get a better intuitive feel of the behavior of system parameters. If $V_i \approx V_j/\tau_k$,

$$\partial P_{ijk}/\partial\theta_{ij} = \partial P_{ijk}/\partial\alpha_k \approx (V_i)^2(G_k \sin(\theta_{ij}+\alpha_k) - B_k\cos(\theta_{ij}+\alpha_k))$$

$$\partial P_{ijk}/\partial V_i \approx V_i[G_k (2 - \cos(\theta_{ij}+\alpha_k)) - B_k\sin(\theta_{ij}+\alpha_k)]$$

If θ_{ij} is close to 0 then $\sin(\theta) \approx \theta$ and $\cos(\theta) \approx 1$. In addition if $V_i \approx V_j/\tau_k$, and $R_k << X_k$ then $G_k \approx 0$ and $B_k \approx -1/X_k$.

$$\partial P_{ijk}/\partial\theta_{ij} = \partial P_{ijk}/\partial\alpha_k \approx V_i^2/X_k$$

$$\partial P_{ijk}/\partial V_i \approx 0$$

$$\partial P_{ijk}/\partial R_k \approx (V_i^2 - (V_iV_j/\tau_k))/X_k^2 \approx 0$$

$$\partial P_{ijk}/\partial X_k \approx -\theta_{ij}V_i^2/X_k^2.$$

When the assumptions are not met the approximations may not be very useful and they may lead to poor results.

The basic equation for defining the reactive power flow along line k from bus i = I(k) towards bus j = J(k) is:

$$Q_{ijk} = -B_k[V_i^2 - (V_iV_j/\tau_k)\cos(\theta_{ij} + \alpha_k)] - G_k(V_iV_j/\tau_k)\sin(\theta_{ij} + \alpha_k) - V_i^2 B_{capik}$$

$$Q_{jik} = -B_k[(V_j/\tau_k)^2 - (V_iV_j/\tau_k)\cos(\theta_{ji} - \alpha_k)] - G_k(V_iV_j/\tau_k)\sin(\theta_{ji} - \alpha_k) - (V_j/\tau_k)^2 B_{capjk}$$

where B_{capik} and B_{capjk} are the shunt susceptances at each end of the line representing the line charging capacitance of line k. Each term is equal to half the total line charging susceptance of the line.

The partial derivatives of reactive power with respect to the phase angle and the voltage at bus i are:

$$\partial Q_{ijk}/\partial\theta_{ij} = \partial Q_{ijk}/\partial\alpha_k = -(V_iV_j/\tau_k)(B_k\sin(\theta_{ij}+\alpha_k) - G_k\cos(\theta_{ij}+\alpha_k))$$

$$\partial Q_{ijk}/\partial V_i = -B_k[2V_i - (V_j/\tau_k)\cos(\theta_{ij} + \alpha_k)] - G_k(V_j/\tau_k)\sin(\theta_{ij} + \alpha_k) - 2V_iB_{capik}$$

The partial derivatives of reactive power with respect to conductance and susceptance are:

$$\partial Q_{ijk}/\partial G_k = -(V_iV_j/\tau_k)\sin(\theta_{ij}+\alpha_k)$$

$$\partial Q_{ijk}/\partial B_k = -(V_i^2 - (V_iV_j/\tau_k)\cos(\theta_{ij}+\alpha_k))$$

The partial derivatives of reactive power with respect to resistance and impedance are:

$$\partial Q_{ijk}/\partial R_k = (\partial Q_{ijk}/\partial G_k)(\partial G_k/\partial R_k) + (\partial Q_{ijk}/\partial B_k)(\partial B_k/\partial R_k) =$$

$$= -\partial B_k/\partial R_k[V_i^2 - (V_iV_j/\tau_k)\cos(\theta_{ij}+\alpha_k)] - \partial G_k/\partial R_k(V_iV_j/\tau_k)\sin(\theta_{ij}+\alpha_k)]$$

$$= -\{2R_kX_k[V_i^2-(V_iV_j/\tau_k)\cos(\theta_{ij}+\alpha_k)] + [(X_k^2 - R_k^2)(V_iV_j/\tau_k)\sin(\theta_{ij}+\alpha_k)]\}/(R_k^2 + X_k^2)^2$$

$$\partial Q_{ijk}/\partial X_k = (\partial Q_{ijk}/\partial G_k)(\partial G_k/\partial X_k) + (\partial Q_{ijk}/\partial B_k)(\partial B_k/\partial X_k) =$$

$$= -\partial B_k/\partial X_k[V_i^2 - (V_iV_j/\tau_k)\cos(\theta_{ij}+\alpha_k)] - \partial G_k/\partial X_k(V_iV_j/\tau_k)\sin(\theta_{ij}+\alpha_k)]$$

$$= -\{(X_k^2 - R_k^2)[V_i^2-(V_iV_j/\tau_k)\cos(\theta_{ij}+\alpha_k)] - 2R_kX_k (V_iV_j/\tau_k)\sin(\theta_{ij}+\alpha_k)\}/(R_k^2 + X_k^2)^2$$

If $V_i \approx V_j/\tau_k$, we have

$$\partial Q_{ijk}/\partial\theta_{ij} = \partial Q_{ijk}/\partial\alpha_k = -(V_i)^2(B_k\sin(\theta_{ij}+\alpha_k) + G_k\cos(\theta_{ij}+\alpha_k))$$

$$\partial Q_{ijk}/\partial V_i = -V_i\{B_k[2- \cos(\theta_{ij}+\alpha_k)] + G_k\sin(\theta_{ij}+\alpha_k) + 2B_{capik}\}.$$

$$\partial Q_{ijk}/\partial R_k = -V_i^2\{2R_kX_k[1-\cos(\theta_{ij}+\alpha_k)] + [(X_k^2 - R_k^2)\sin(\theta_{ij}+\alpha_k)]\}/(R_k^2+X_k^2)^2$$

$$\partial Q_{ijk}/\partial X_k = -V_i^2\{(X_k^2 - R_k^2)[1-\cos(\theta_{ij}+\alpha_k)] - [2R_kX_k \sin(\theta_{ij}+\alpha_k)]\}/(R_k^2+X_k^2)^2$$

If $\theta_{ij} +\alpha_k$ is close to 0, $V_i \approx V_j/\tau_k$, and $R_k << X_k$, we have

$$\partial Q_{ijk}/\partial\theta_{ij} \approx 0$$

$$\partial Q_{ijk}/\partial V_i \approx -2V_i(B_k + B_{capik})$$

$$\partial Q_{ijk}/\partial R_k \approx 0$$

$$\partial Q_{ijk}/\partial X_k \approx 0.$$

Transmission Losses. Although often ignored for computational and presentational simplicity, losses can be a significant factor in system economics. This is especially true for reactive power losses. Transmission losses are essentially the power consumed/absorbed by the transmission asset, and dissipated as heat, as it performs its function of moving or transforming power. For real power, losses (or consumption) for transmission element k are:

$$\ell_{Pk} (\theta, V, t, \alpha) = P_{ijk} + P_{jik} = G_k[V_i^2 + (V_j/\tau_k)^2 - 2(V_iV_j/\tau_k)\cos(\theta_{ij} + \alpha_k)]$$

The partial derivatives of real power losses with respect to voltage and phase angle are:

$$\partial\ell_{Pk}/\partial V_i = 2G_k[V_i - (V_j/\tau_k)\cos(\theta_{ij} + \alpha_k)].$$

$$\partial\ell_{Pk}/\partial\theta_{ij} = \partial\ell_{Pk}/\partial\alpha_k = 2G_k (V_iV_j/\tau_k)\sin(\theta_{ij} + \alpha_k).$$

If we assume $V_i > V_j/\tau_k$, an increase in the high-end voltage increases real losses, but the flow is increased by an even greater amount. If $\theta_{ij} + \alpha_k > 0$, an increase in phase angle increases real losses, but again the flow also increases.

The partial derivative of real power losses with respect to conductance is:

$$\partial\ell_{Pk}/\partial G_k = V_i^2 + (V_j/\tau_k)^2 - 2(V_iV_j/\tau_k)\cos(\theta_{ij} + \alpha_k)$$

Since $\cos(\theta_{ij} + \alpha_k) < 1$, if $V_j/\tau_k < V_i$ then $\partial\ell_{Pk}/\partial G_k > 0$ and an increase in conductance increases losses.

Since $\partial\ell_{Pk}/\partial B_k = 0$, the partial derivatives of real power losses with respect to resistance and reactance are:

$$\partial\ell_{Pk}/\partial R_k = (\partial\ell_{Pk}/\partial G_k)(\partial G_k/\partial R_k) =$$

$$(X_k^2 - R_k^2) [V_i^2 + (V_j/\tau_k)^2 - 2(V_iV_j/\tau_k)\cos(\theta_{ij} + \alpha_k)]/(R_k^2 + X_k^2)^2.$$

If $X_k > R_k$ then $\partial\ell_{Pk}/\partial R_k > 0$.

$$\partial\ell_{Pk}/\partial X_k = (\partial\ell_{Pk}/\partial G_k)(\partial G_k/\partial X_k)$$

$$=(-2X_kR_k)[(V_i)^2 + (V_j/\tau_k)^2 - 2(V_iV_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)]/(R_k^2 + X_k^2)^2$$

Real losses increase as the resistance, voltage difference and phase angle difference increase. For a transmission line, if $X_k \gg R_k$ (as is usually the case), then $G_k \approx 0$ and $\ell_{Pk}(\theta, V, \tau, \alpha) \approx 0$. If the transmission element is a line, as its length increases, the resistance, R_k, increases, X_k increases and losses increase. Resistance and reactance are design parameters and, in some more expensive devices, can be varied in operation. As voltage gets higher, in general, R_k/X_k decreases.

For reactive power losses (or consumption) are:

$$\ell_{Qk}(\theta, V, t, \alpha) = Q_{ijk} + Q_{jik}$$

$$= -B_k[V_i^2 + (V_j/\tau_k)^2 - 2(V_iV_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)] - V_i^2B_{capik} - (V_j/\tau_k)^2B_{capjk}$$

The partial derivative of reactive power losses with respect to voltage is:

$$\partial\ell_{Qk}/\partial V_i = -2B_k[V_i - (V_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)] - 2B_{capik}$$

If V_i is sufficiently larger than V_j/τ_k then an increase in voltage at the high voltage end increases reactive losses (but would also tend to increase voltage at the low voltage end, countervailing this effect.) If $V_i \approx V_j/\tau_k$ then increasing voltage decreases (net) reactive losses.

The partial derivative of reactive power losses with respect to phase angle is:

$$\partial\ell_{Qk}/\partial\theta_{ij} = \partial\ell_{Qk}/\partial\alpha_k = -2B_k(V_iV_j/\tau_k)\sin(\theta_i - \theta_j + \alpha_k)]$$

If $\sin(\theta_i - \theta_j + \alpha_k) > 0$ then an increase in the phase angle increases reactive losses.

The partial derivative of reactive power losses with respect to susceptance is:

$$\partial \ell_{Qk}/\partial B_k = -((V_i)^2 + (V_j/\tau_k)^2 - 2(V_iV_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)).$$

Since $\cos(\theta_i - \theta_j + \alpha_k) < 1$ then $\partial \ell_{Qk}/\partial B_k < 0$.

Since $\partial \ell_{Qk}/\partial G_k = 0$, the partial derivatives of reactive power losses with respect to resistance and reactance are:

$$\partial \ell_{Qk}/\partial R_k = (\partial \ell_{Qk}/\partial B_k)(\partial B_k/\partial R_k)$$

$$= (-2X_kR_k)[(V_i)^2 + (V_j/\tau_k)^2 - 2(V_iV_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)]/(R_k^2 + X_k^2)^2$$

$$\partial \ell_{Qk}/\partial X_k = (\partial \ell_{Qk}/\partial B_k)(\partial B_k/\partial X_k)$$

$$= (-X_k^2 + R_k^2)[(V_i)^2 + (V_j/\tau_k)^2 - 2(V_iV_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)]/(R_k^2 + X_k^2)^2$$

Reactive power losses decrease with increasing susceptance, B_k, increase with the phase angle difference, voltage differences and can be offset with additional capacitor capacity.

If $V_i \approx V_j/\tau_k$,

$$\ell_{Qk}(\theta, V, \tau, \alpha) = V_i^2\{-2B_k[1 - \cos(\theta_i - \theta_j + \alpha_k)] - B_{capik} - B_{capjk}\}.$$

When $-2B_k[1 - \cos(\theta_i - \theta_j + \alpha_k)] = B_{capik} + B_{capjk}$, $\ell_{Qk} = 0$.

The point at which $\ell_{Qk} = 0$ is called the surge impedance loading. It is easy to see how a capacitor can offset reactive power losses. Capacitors are often installed in banks and deployed as needed. As the phase angle moves away from 0, reactive losses (or consumption) increase.

If $X_k \gg R_k$ (as is usually the case), then $B_k \approx -1/X_k$ and $\ell_{Qk}(\theta, V, \tau, \alpha)$ is usually non-zero. If the transmission element is a line, as it gets longer, the resistance, R_k, increases, X_k increases and losses increase. As nominal voltage class gets higher, in general, R_k / X_k decreases.

If $\theta_{ij} + \alpha_k \approx 0$ and $V_i \approx V_j/\tau_k$,

$$\partial\ell_{Qk}/\partial V_i = -2B_k [V_i - (V_j/\tau_k)\cos(\theta_{ij}+ \alpha_k)] - 2\ V_iB_{capik} \approx -2V_iB_{capik}$$

$$\partial\ell_{Qk}/\partial\theta_{ij} \approx -2B_k(V_iV_j/\tau_k)(\theta_{ij}+ \alpha_k)$$

$$\partial\ell_{Qk}/\partial R_k = -2R_k [V_i - (V_j/\tau_k)\cos(\theta_{ij}+ \alpha_k)] - 2\ V_i\ B_{capik}]/ X_k^3 \approx 0$$

$$\partial\ell_{Qk}/\partial X_k = -[(V_i)^2 + (V_j/\tau_k)^2 - 2(V_iV_j/\tau_k)]/X_k^2 \approx 0$$

If $X_k \gg R_k$, $B_k \gg G_k$ then reactive losses are much greater than real losses:

$$\ell_{Qk}(\theta, V, \tau, \alpha) \gg \ell_{Pk}(\theta, V, \tau, \alpha).$$

Operating Costs. Although we will examine a single transmission element, this analysis can be extended to more than two buses by presenting prices and quantities at the priced buses or nodes. We will further assume that in the time period t the physical depreciation and operating costs are essentially negligible. We have the following constraints.

Conservation of Energy:

$$P_{ijk} + P_{jik} - \ell_{Pk} = 0 \qquad \lambda_P \qquad (1)$$

$$Q_{ijk} + Q_{jik} - \ell_{Qk} = 0 \qquad \lambda_Q \qquad (2)$$

where λ_P is value of another unit of real power transferred and
λ_Q is value of another unit of reactive power transferred.

Thermal Limits: If the thermal limit, in MVA, is MVA^{max}, then:

$$[(P_{ijk})^2+(Q_{ijk})^2]^{1/2} + TRM - MVA^{max} \leq 0 \qquad \lambda_{MVAi} \qquad (3i).$$

$$[(P_{jik})^2+(Q_{jik})^2]^{1/2} + TRM - MVA^{max} \leq 0 \qquad \lambda_{MVAj} \qquad (3j).$$

where λ_{MVAi} is the value of another unit of thermal capacity at bus i.

The thermal limit is often simplified to $P_{ijk} + TRM - MW^{max} \leq 0$ where MW^{max} is adjusted in magnitude to account for the simplification. An approximation can be derived from the first order Taylor series expansion,

---

$$b_{Pijk}P_{ijk} + b_{Qijk}Q_{ijk} + TRM - \underline{MVA}^{max} \leq 0$$

where b_{Pijk}/b_{Qijk} is the tradeoff between real and reactive power when the element is at its limit and $\underline{MVA}^{max}$ is the adjusted capacity including the constant terms of the linearization (an alternative approach would be to supply a piecewise linear function as an approximation to the quadratic function.).

Miscellaneous Surrogate Constraints. Some other constraints can be formulated as:

$$P_{ijk} - MW^h \leq 0 \qquad \lambda_h \qquad (h = 5,\ldots, n)$$

where $\lambda = (\lambda_P, \lambda_Q, \lambda_{MVA}, \lambda_h)$ is a vector of marginal values (dual variables or Lagrange multipliers).

Power Inputs, Outputs and Losses. Real losses are induced by current in a line and are equal to I^2R. An increase in current increases the temperature in the wires. High temperatures can cause equipment damage.

Operating Reserves. Transmission reserves should be determined and priced simultaneously in auctions or power systems optimizations.

Efficient Operations. Efficient operations require that the TO produce the optimal output at least cost. In many cases once an asset is in-service the operation is passive. This is true for both a vertically integrated utility and ISO markets. In a vertically integrated utility, the dual variables or Lagrange multipliers from the optimal power flow model are transfer prices. In an ISO, the Lagrange multipliers are the prices. The revenues in time period t are

$$p_t(P_t, Q_t, TRM_t, MVA_t^{max}, R_t, X_t, \tau_t, \alpha_t, Bcap_t)'$$

where $p_t = (p_{Pti}, p_{Ptj}, p_{Qti}, p_{Qtj}, p_{TRMt}, p_{MVAt}, p_{Rt}, p_{Xt}, p_{\tau t}, p_{\alpha t}, p_{Bcapt})$ is a price vector,
p_{Pti}, p_{Ptj} is the price of real power buses i and j in time period t,
p_{Qti}, p_{Qtj} is the price of reactive power buses i and j in time period t,
p_{TRMt} is the price of transmission margin in time period t, …

Revenues depend on the bus prices and the amount of real and reactive power injected or withdrawn at each bus.

Soft Constraints. In emergencies, equipment is often operated beyond rated, nominal or steady-state limits for short periods of time. As formulated, the production possibilities set is composed of hard constraints. To soften the constraint, we introduce MVA^{max} as a real time parameter

---

variable. If MVA^{maxr} is the rated capacity, we can make MVA^{max} a variable with the following entry in the cost function:

$$c_{MVA}(MVA^{max}) = (MVA^{max}/MVA^{maxr})^m$$

For m large and $MVA^{max} < MVA^{maxr}$, $c_{MVA}(MVA^{max})$ is close to 0. For m large and $MVA^{max} > MVA^{maxr}$, $c_{MVA}(MVA^{max})$ increases quickly when MVA^{max} becomes larger than MVA^{maxr}. The function, $c_{MVA}(MVA^{max})$, can be much more detailed, but for this discussion the polynomial will suffice. This can be closely approximated by a piecewise linear function. This type of cost function has been described as a 'hockey stick' curve because it is very steep beyond MVA^{maxr}. In a multi-period setting, the amount of time an asset can be operated beyond its rating can be specified similarly to the way that downtime is modeled for generators. This process can be used to soften other constraints.

If the asset has additional cooling capability, the thermal capacity of the asset becomes variable.

MVA^{maxr} = f(cooling temperature, wind speed) and

$c_c(MVA^{maxr})$ is the costs of changing MVA^{maxr}

Now, the cost function becomes

$$c_{MVA}(MVA^{max}, MVA^{maxr}) = (MVA^{max}/MVA^{maxr})^m + c_c(MVA^{maxr}).$$

Profit Maximization or Cost Minimization. For time period t, given prices, p, (we drop the subscript, t, to ease the presentation) and ignoring losses, we form the Lagrangean: the TO maximizes profits by solving the Lagrangean optimization:

$L(P, Q, TRM, MVA^{max}, R, X, \alpha, \tau, Bcap, \lambda) =$

$p(P, Q, TRM, MVA^{max}, R, X, \alpha, \tau, Bcap) - c_{MVA}(MVA^{max}, MVA^{maxr})$

$- \lambda K(P_i, P_j, Q_i, Q_j, TRM, MVA^{max}, R, X, \alpha, \tau, Bcap)$

where $K(P_i, P_j, Q_i, Q_j, TRM, MVA^{max}, R, X, \alpha, \tau, Bcap) \leq 0$ can be represented as:

$P_{ijk} + P_{jik} - \ell_{Pk} = 0$ $\qquad\qquad\qquad \lambda_P \qquad$ (1)

$Q_{ijk} + Q_{jik} - \ell_{Qk} = 0$ $\qquad\qquad\qquad \lambda_Q \qquad$ (2)

$b_{Pijk}P_{ijk} + b_{Qijk}Q_{ijk} + TRM - \underline{MVA}^{max} \leq 0$ $\qquad$ λ_{MVAi} $\quad$ (3i).

$b_{Pjik}P_{jik} + b_{Qjik}Q_{jik} + TRM - \underline{MVA}^{max} \leq 0$ $\qquad$ λ_{MVAj} $\quad$ (3j)

$P_{ijk} - MW^h \leq 0$ $\qquad\qquad\qquad\qquad$ λ_h $\quad$ (5,…, n)

> where $\lambda = (\lambda_P, \lambda_Q, \lambda_{MVAi}, \lambda_{MVAj}, \lambda_h)$ is a vector of marginal values (dual variables or Lagrange multipliers).

Prices and quantities for real and reactive power (λ_P, λ_Q) can be positive or negative. When p_Q is negative and Q is negative, the payment is positive. If a constraint is not binding, the associated λ_h is 0. When Karush-Kuhn-Tucker conditions (see [4] and [5]) are satisfied, there is a solution to the problem. We now find the maximum of the Lagrangean. The optimality conditions include choosing the optimal parameter settings of MVA^{max}, R, X, α, τ, Bcap to satisfy: (since it is not needed, we drop the subscribe k)

$\partial L/\partial P_{ij} = p_{Pij} - \sum_h \lambda_h \partial K_h/\partial P_{ij} = 0$ or

$p_{Pij} = \lambda_P(1 + \partial P_{ji}/\partial P_{ij} - \partial \ell_P/\partial P_{ij}) + \lambda_{MVAi}b_{Pij} + \sum_h \lambda_h$

$\partial L/\partial Q_{ij} = p_{Qij} - \sum_h \lambda_h \partial K_h/\partial Q_{ij} = 0$ or

$p_{Qij} = \lambda_Q(1 + \partial Q_{ji}/\partial Q_{ij} - \partial \ell_Q/\partial Q_{ij}) + \lambda_{MVAi}b_{Qij}$

$\partial L/\partial MVA^{max} = p_{MVAmax} - \partial c/\partial MVA^{max} - \sum_h \lambda_h \partial K_h/\partial MVA^{max} = 0$ or

$p_{MVAmax} = \partial c/\partial MVA^{max} + \lambda_{MVAi} + \lambda_{MVAj}$

$\partial L/\partial X = p_X - \sum_h \lambda_h \partial K_h/\partial X = 0$ or

$p_X = \lambda_P(\partial P_{ij}/\partial X + \partial P_{ji}/\partial X - \partial \ell_P/\partial X) + \lambda_Q(\partial Q_{ij}/\partial X + \partial Q_{ji}/\partial X - \partial \ell_Q/\partial X)$

$\partial L/\partial R = p_R - \sum_h \lambda_h \partial K_h/\partial X = 0$ or

$p_R = \lambda_P(\partial P_{ij}/\partial R + \partial P_{ji}/\partial R - \partial \ell_P/\partial R) + \lambda_Q(\partial Q_{ij}/\partial R + \partial Q_{ji}/\partial R - \partial \ell_Q/\partial R)$

$\partial L/\partial \tau = p_\tau - \partial c/\partial \tau - \sum_h \lambda_h \partial K_h/\partial \tau$ or

---

Principles for Efficient and Reliable Reactive Power Supply and Consumption **157**

$$p_\tau = \lambda_P(\partial P_{ij}/\partial\tau + \partial P_{ji}/\partial\tau - \partial\ell_P/\partial\tau) + \lambda_Q(\partial Q_{ij}/\partial\tau + \partial Q_{ji}/\partial\tau - \partial\ell_Q/\partial\tau)$$

$$\partial L/\partial\alpha = p_\alpha - \sum_h \lambda_h \partial K_h/\partial\alpha = 0. \text{ or}$$

$$p_\alpha = \lambda_P(\partial P_{ij}/\partial\alpha + \partial P_{ji}/\partial\alpha - \partial\ell_P/\partial\alpha) + \lambda_Q(\partial Q_{ij}/\partial\alpha + \partial Q_{ji}/\partial\alpha - \partial\ell_Q/\partial\alpha)$$

$$\partial L/\partial Bcapi = p_{Bcap} - \sum_h \lambda_h \partial K_h/\partial Bcapi = 0.$$

$$p_{Bcapi} = \lambda_Q(\partial Q_{ij}/\partial Bcapi - \partial\ell_Q/\partial Bcapi)$$

This optimization depends on variable control over a variety of parameters, many of which are not currently variable, including line limits, resistance and reactance.

Summary. This appendix examined the investment and operating decisions of active transmission market participants. Its intention is to stimulate discussion of introducing active transmission participation into the market.

References:

1. Arthur R. Bergen and Vijay Vittal, *Power System Analysis*, 2nd Ed., Prentice Hall, 2000.

2. Charles A. Gross, *Power System Analysis*, Wiley, New York, 1979.

3. William W. Hogan, "Financial Transmission Right Formulations," Harvard University, March 31, 2002, submitted to FERC in RM01-12-000.

4. David Luenberger, *Optimization by Vector Space Methods*, Wiley, New York, 1969.

5. Oliv Mangasarian, *Nonlinear Programming*, McGraw-Hill, New York, 1969.

6. Richard O'Neill, Ross Baldick, Udi Helman, Michael H. Rothkopf and William Stewart Jr., "Dispatchable Transmission in RTO Markets," *IEEE Transactions on Power Systems*, to appear.

7. R.P. O'Neill, U. Helman, B.F. Hobbs, W.R. Stewart and M.H. Rothkopf, "A Joint Energy and Transmission Rights Auction: Proposal and Properties," *IEEE Transactions on Power Systems*, 17(4), November 2002, 1058-1067.

8. Richard P. O'Neill, Paul M. Sotkiewicz, Benjamin F. Hobbs, Michael H. Rothkopf and William R. Stewart Jr., "Efficient Market-Clearing Prices in Markets with Nonconvexities," *European Journal of Operational Research*, Vol. 164/1, 269-285.

9. Krishnan Dixit and Ross Baldick, "An Empirical Study of the Economies of Scale in AC Transmission Line Construction Costs," December 2003.

An Engineering and Economic Analysis of a System Operator's Real and Reactive Power Planning and Markets

The system operator's job is to efficiently plan and operate the system using the constrained assets along with associated bids or costs. In this appendix, the system operator neither owns nor operates electric assets, but gives signals or messages to generators, transmission owner/operators and load that define how the system should be operated. We also assume that the information system is noiseless and has accurate system measurement, e.g., revenue quality meters but make comments on potential noise problems. The system operator can be considered an ISO or a separate function in a vertically integrated utility. The system operator's investments are in software, hardware and personnel, and responsibilities include reliability planning and operation.

In these appendices the approach taken is indifferent to whether the system operator is independent or a vertically integrated utility. If the system operator is independent, it must monitor and mitigate market power of market participants. Through market design, the electric asset owner/operators should have profit incentives to be efficient. Large firms often simulate competition internally by using transfer pricing between functional units like system operation, generation operation and transmission operation. If the system operator is a vertically integrated utility, the prices become transfer prices for internal transactions, but the efficiency incentives are usually blunted by the overall regulatory scheme.

Electricity is unusual in that when a generating or transmission unit is lost and prices go up, demand response is minimal and, in extreme cases, load must be removed from the system to prevent wide-spread system collapse. Because of the low level of demand response, and need for carefully balanced generation and load, networks tend to be designed conservatively. Wood and Wollenberg state, "Networks are designed with large capacity margins so that the elements tend to be loaded conservatively." (See reference [7].) To enforce this conservative loading and maintain grid performance, the system employs three types of constraints: thermal, voltage, and stability. Thermal constraints arise from overheating of equipment leading to damage and poor performance. Voltage is controlled by supplying and consuming reactive power. Stability limitations are part art form based on experience and selected simulations. As computation speed increases, software improves and costs decrease, more analysis can be performed both closer to real time and in forward planning leading to greater efficiency and reliability.

The state of the power system is defined by voltage and phase angles at system nodes. Here we ask the optimal AC power flow (AC OPF) software to find the optimum output in terms of P and Q. This includes optimal voltage schedules and settings of transformer taps, switched capacitors and FACTS devices. The system operator's management of reactive resources involves equipment capability and actual delivery. That is, the system operator must have control over

enough reactive power capability to produce and absorb reactive power in response to the time-varying and location-specific requirements of the system to control voltage efficiently. An AC constrained optimal-power-flow analysis can determine the reactive power dispatch that maximizes benefits to the system.

In a competitive environment, determination of who has provided what service will be more important. Basing generation schedules or payment on claimed capability may not be adequate. The actual reactive power output from a generator may not match the manufacturer's capability specifications. Adjustment of tap settings on the step-up (and other) transformers, adjustment of station service voltage levels, and recalibrating and setting alarms and meters (and sometimes replacing meters) are often needed to increase the actual reactive power output.

Today, ISOs run centralized capacity, transmission rights, day-ahead and real-time markets for real power. These auctions can be extended to include reactive power. Again the approach taken in this appendix is indifferent between a vertically integrated utility and an ISO. In a capacity market auction we can no longer neglect the discrete nature of investment choices, but the auction process no longer has tight time windows to be completed like the DAM and RTM. Here we outline a capacity auction for reactive power.

Computational and Modeling Issues. Some argue that a full AC model would be computationally burdensome. Significant computer hardware advances and advances in market software design, driven by market design changes, e.g., PJM, NYISO and ISO-NE, have been made in the last decade. In 1996, a 300-node network market model in New Zealand was the state of the art. Currently, a 30,000-node model with greater network detail is being solved faster than the 300-node model in 1996. As yet, there is no production software the can perform a full AC constrained optimal-power.

Problems, once considered practically unsolvable, are now solved in several minutes. These advances allow a convergence of reliability and market software. The limiting factor seems to be data quality (garbage in, garbage out). Even with all these advances, reactive power and voltage control is still a challenge. Robust optimal solutions to a security constrained AC OPF that includes reactive power and voltage control are still elusive and require more research and development.

To date, reactive power management in bulk power systems has been based on establishing pre- and post-contingency voltage limits. Generators are given voltage schedules. Control devices, such as transformer taps, shunt capacitors/reactors and generator voltages, are set to maintain voltages within the limits, using a variety of manual and local automatic control. Many controls can be adjusted at most a few times in a day.

Reactive power limits are also managed implicitly via surrogate transmission limits. Thermal limits are de-rated to account for reactive power flows. Interface limits are often surrogate

constraints associated with voltage, voltage drop, and voltage stability. Must-run units are identified through off-line studies. Because these approaches do not base limits on actual reactive power values and are updated infrequently, they often necessitate large and imprecise safety margins that can reduce the utilization for the power system.

Today, the standard market operation system package does not include reactive power as part of the co-optimization of real power with reserves. The real and reactive controls are mathematically cross-coupled. In the ideal OPF formulation, real and reactive controls are considered simultaneously subject to all constraints with a single cost objective function. Intertemporal constraints need to be modeled similar to the approach to generator unit commitment. To date convergence and formulation problems have prevented usable engineering solutions. Currently, active and reactive power controls are optimized separately leading to suboptimal solutions.

We need to bring more science into what is still seen by many as an engineering art form. A modular and flexible approach to modeling the problem will allow less expensive incorporation of the necessary algorithms for co-optimizing with reactive power. To support better software development, data quality needs improvement. ISO New England is currently engaged in projects to evaluate sensitivities during system congestion and the difference between proxy-based voltage constraints and explicit modeling in the OPF.

Conservation of Complex Power Balancing Equations. The power flow at each bus in a network must obey the conservation of power laws. For simplicity we assume one generator or load at each bus. For real power at each bus i and each connecting transmission element k , the conservation of real power yields:

$$H_{Pi}(P_i, V, \theta, u) = P_i - \sum_k P_{ijk} = 0,$$

where $P_{ijk} = G_k[V_i^2 - (V_iV_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)] - B_k(V_iV_j/\tau_k)\sin(\theta_i - \theta_j + \alpha_k)$, the real power flow from bus i to bus j on transmission element k. If i is not a terminal bus for k, $G_k = B_k = P_{ijk} = 0$.

For reactive power at each bus i, conservation of reactive power yields:

$$H_{Qi}(Q_i, V, \theta, u) = Q_i - \sum_k Q_{ijk} = 0,$$

where $Q_{ijk} = -B_k[V_i^2 - (V_iV_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)] - G_k(V_iV_j/\tau_k)\sin(\theta_i - \theta_j + \alpha_k) - V_i^2 B_{capik}$, the reactive power flow from bus i to bus j on transmission element k. If i is not a terminal bus for k, $G_k = B_k = Q_{ijk} = 0$.

Bus 0 is defined as the swing, slack or reference bus and we define 2n independent bus balancing equations in vector form:

$$H_P(P,V,\theta, u) = (H_{P1}(P_1,V,\theta, u),\ldots, H_{Pn}(P_n,V,\theta, u)) = 0.$$

$$H_Q(Q,V,\theta, u) = (H_{Q1}(Q_1,V,\theta, u),\ldots, H_{Qn}(Q_n,V,\theta, u)) = 0.$$

We define the Jacobian matrices of partial derivatives as:

$$J_{11} = [\partial P_i/\partial\theta_j]_{ij} \quad J_{12} = [\partial P_i/\partial V_j]_{ij} \quad J_{21} = [\partial Q_i/\partial\theta_j]_{ij} \quad J_{22} = [\partial Q_i/\partial V_j]_{ij}$$

where i, j = 1,…, n and $[\ ]_{ij}$ is the entry for i^{th} row and j^{th} column.

For i ≠ j,

$$\partial P_i/\partial\theta_j = -\sum_k \{(V_iV_j/\tau_k)[G_k\sin(\theta_i - \theta_j + \alpha_k) - B_k\cos(\theta_i - \theta_j + \alpha_k)]\};$$

$$\partial P_i/\partial V_j = -\sum_k \{(V_i/\tau_k)[G_k\cos(\theta_i - \theta_j + \alpha_k) + B_k\sin(\theta_i - \theta_j + \alpha_k)]\};$$

$$\partial Q_i/\partial\theta_j = \sum_k \{(V_iV_j/\tau_k)[G_k\cos(\theta_i - \theta_j + \alpha_k) + B_k\sin(\theta_i - \theta_j + \alpha_k)]\}; \text{ and}$$

$$\partial Q_i/\partial V_j = \sum_k \{(V_i/\tau_k)[-G_k\sin(\theta_i - \theta_j + \alpha_k) + B_k\cos(\theta_i - \theta_j + \alpha_k)]\}.$$

Also,

$$\partial P_i/\partial\theta_i = \sum_k \{(V_iV_j/\tau_k)[G_k\sin(\theta_i - \theta_j + \alpha_k) - B_k\cos(\theta_i - \theta_j + \alpha_k)]\};$$

$$\partial P_i/\partial V_i = \sum_k \{G_k[2V_i - (V_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)] - B_k(V_j/\tau_k)\sin(\theta_i - \theta_j + \alpha_k)\};$$

$$\partial Q_i/\partial\theta_i = -\sum_k \{ (V_iV_j/ \tau_k)[G_k\cos(\theta_i - \theta_j + \alpha_k) + B_k\sin(\theta_i - \theta_j + \alpha_k)]\}; \text{ and}$$

$$\partial Q_i/\partial V_i = -\sum_k \{B_k[2V_i - (V_j/\tau_k)\cos(\theta_i - \theta_j + \alpha_k)] + G_k(V_j/\tau_k)\sin(\theta_i - \theta_j + \alpha_k)] + 2V_iB_{capik}.\}.$$

In each the summation over k must be taken over the appropriate transmission elements.

Decoupling the Power Flow. To solve these equations simplifications are often made based on actual system operations. If we assume $R_k << X_k$, then $G_k << B_k$. We assume no shunt reactances to ground and no shunts to ground from autotransformers. If we assume no phase shifting transformers, then $\alpha_k = 0$. Additionally, we assume, $\theta_i - \theta_j \approx 0$ and $\tau_k = 1$, the simplifications yield:

$$H_{Pi} (P_i,V, \theta, u) \approx P_i - \sum_k G_k[V_i^2 - V_iV_j] + \sum_k B_kV_iV_j(\theta_i - \theta_j) \approx 0, \quad i = 0, 1,\ldots, n$$

$$H_{Qi} (Q_i,V, \theta, u) \approx Q_i + \sum_k B_k [V_i^2 - V_iV_j] + \sum_k G_kV_iV_j(\theta_i - \theta_j) \approx 0, \quad i = 0, 1,\ldots, n$$

$\partial P_i/\partial V_j \approx -\sum_k V_i[G_k + B_k(\theta_i - \theta_j)\ ]\approx 0,$
where the sum includes all elements k connecting i and j,

$\partial Q_i/\partial \theta_j \approx \sum_k (V_iV_j)[G_k]\approx 0,$
where the sum includes all elements k connecting i and j,

For $i \neq j$,

$\partial P_i/\partial \theta_j \approx V_iV_j\sum_k B_k$ and let $\underline{B}_{ij} = V_j\sum_k B_k,$
where the sum includes all elements k connecting i and j

$\partial Q_i/\partial V_j \approx V_i\sum_k B_k,$ and let $B_{ij} = \sum_k B_k,$
where the sum includes all elements k connecting i and j.

Also,

$\partial P_i/\partial \theta_i \approx -V_i\sum_j V_j\sum_k B_k$ and let $\underline{B}_{ii} =-\sum_j V_j\sum_k B_k,$
where the sum includes all elements k connecting to i for each j.

$\partial Q_i/\partial V_i \approx -V_i\sum_k B_k$ and $B_{ii} = -\sum_k B_k,$
where the sum includes all elements k connecting to i for each j.

Let $\Delta P/V = (\Delta P_1/V_1,\ldots, \Delta P_n/V_n)$, $\Delta Q/V = (\Delta Q_1/V_1,\ldots, \Delta Q_n/V_n)$, $\Delta V = (\Delta V_1,\ldots, \Delta V_n)$,
$\Delta \theta = (\Delta \theta_1,\ldots, \Delta \theta_n)$ and $\underline{B} = [\underline{B}_{ij}]_{ij}$, we obtain the DC power flow model:

$\Delta P/V = \underline{B}\Delta \theta$

As can be seen the DC model assumes constant voltage and is blind to reactive power, but is easier to solve than the AC model. Voltage constraints are approximated with proxy thermal constraints.

The decoupled AC model is:

$\Delta P/V = \underline{B}\Delta \theta$ and $\Delta Q/V = B\Delta V$

The system is solved by fixing voltages solving the DC equations, then solving the reactive equations and iterating between the two sets of equations to achieve the best result. Both DC model and the iterative model approaches arose out of a need to simplify the computation. As hardware advances are made, computational constraints are less important, although these approximations may still be useful in solving the coupled equations rapidly. The remaining challenge is to find an optimal solution to the highly nonconvex AC optimization problem. More work needs to be done to improve the optimization techniques.

Voltage Limits. Voltage limits, based on results of system studies, are assigned to buses in order to maintain grid stability. :

$$V_i^{min} \leq V_i \leq V_i^{max} \qquad \lambda_{Vimin}, \lambda_{Vimax} \qquad i = 1,\ldots, n$$

If $V_i = V_i^{max}$ or $V_i = V_i^{min}$, the dual variable can be different from zero. In the computer algorithms, equality constraints are approximate. Software requires acceptable tolerances for zero. All constraints are, in effect, inequality constraints. Instead of constraints like $V_i^{min} \leq V_i \leq V_i^{max}$, a cost of voltage deviation could be added to the objective function to represent the possibility, yet high cost of, voltage deviations. The function should have steep slopes when approaching limits. For example, dropping the subscript i, let

$$V - v^{max+} + v^{max-} = V^{max} \text{ with } v^{max+}, v^{max-} \geq 0,$$

$$V - v^{min+} + v^{min-} = V_{min}; v^{min+}, v^{min-} \geq 0, \text{ and}$$

$$c_V(V; V^{min}, V^{max}) = (v^{max+})^m + (v^{min-})^m.$$

the variable, v^{max+}, measures the excursion outside the 'deadband' or target range on the high voltage side and the variable, v^{min-}, measures the excursion outside the 'deadband' or target range on the low voltage side.

In an optimization if $V > V^{max}$, $v^{max+} > 0$, then $v^{max-} = v^{min+} = v^{min-} = 0$. If $V < V^{min}$, $v^{min-} > 0$, then $v^{max-} = v^{min+} = v^{max-} = 0$. If $V^{min} < V < V^{max}$, $v^{max+} = v^{min-} = 0$, then $c_V(V; V^{min}, V^{max}) = 0$. The magnitude of m sends a price signal for 'violating' the hard constraint, $V^{min} \leq V \leq V^{max}$. The marginal cost is

$$\partial c_V/\partial V = m(v^{max+})^{m-1} + m(v^{min-})^{m-1}.$$

If V is outside the range $[V^{min}, V^{max}]$, the $c_V(V; V^{min}, V^{max})$ increases rapidly depending on m. The function, $c_V(V; V^{min}, V^{max})$, could be interpreted as an insurance premium for voltage collapse that is a function of where the system operates. An analogous construct can be used for frequency, but we omit it here to avoid additional notation. Certain loads may want even smaller tolerances on voltages. They could submit bids with smaller tolerances.

The AC Optimal Power Flow Auction. The system operator acts as an auctioneer by taking bids from market participants. Each generator submits a bid of the form:

$b_{Gi}(P, Q, u_{Gi})$ subject to operating constraints, $K_{Gi}(P, Q, u_{Gi}) \leq 0$ where u_{Gi} is a vector of control variables for $i = 1,..., I$

Each transmission operator submits a bid of the form:

$b_{Tk}(P, Q, u_{Tk})$ subject to operating constraints, $K_{Tk}(P, Q, u_{Tk}) \leq 0$, where u_{Tk} is a vector of control variables for $k = 1,..., K$.

With some loss in approximation, both bids can be required to be linear mixed-integer in both the bid function and the constraint function. We have purposely created bid parameters for transmission that were previously considered fixed. FACTS technology, in particular, enables these parameters to be varied. The bus chosen for the market transaction can be limited to a subset of buses or nodes that can be aggregated for the convenience of financial trading. In practical terms the system operator has a representation of both generation and transmission bid and constraint functions, and changes are submitted periodically.

The system operator solves the following AC optimal power flow problem that may include some mitigation of the bids:

$$\text{Max } W(P,Q,u) = \sum_i b_{Gi}(P,Q,u_{Gi}) + \sum_k b_{Tk}(P,Q,u_{Tk}) - \sum_i c_{Vi}(V_i; V_i^{min}, V_i^{max})$$

subject to

$$K_G(P,Q,u) \leq 0, \qquad \mu_G$$

$$K_T(P,Q,u) \leq 0 \qquad \mu_{Tk}$$

$$H_P(P,V,\theta, u) = 0, \qquad \lambda_P$$

$$H_Q(Q,V,\theta, u) = 0, \qquad \lambda_Q.$$

where $K_G(P,Q,u) = (K_{G1}(P,Q,u_1), \ldots, K_{Gn}(P,Q,u_n)), \qquad \mu_G = (\mu_{G1}, \ldots, \mu_{Gn}),$

$\qquad K_T(P,Q,u) = (K_{T1}(P,Q,u_1), \ldots, K_{Tn}(P,Q,u_n)), \qquad \mu_T = (\mu_{T1}, \ldots, \mu_{Tn})$

$\qquad H_P(P,V,\theta) = (H_{P1}(P_1,V,\theta), \ldots, H_{Pn}(P_n,V,\theta)), \qquad \lambda_P$

$\qquad H_Q(Q,V,\theta) = (H_{Q1}(Q_1,V,\theta), \ldots, H_{Qn}(Q_n,V,\theta)), \qquad \lambda_Q.$

If the problem is formulated as a mixed-integer nonlinear program, we can allow discrete system changes like generation start-up, breaker status and phase shifter settings. (See references [6], [7] and [8].) To avoid making the problem overly complex, we will continue with only continuous variables.

To solve AC optimal power flow auction problem, we define the Lagrangean function as

---

Max L(P, Q, u, λ, μ) =

$$W(P,Q,u) - \mu_G K_G(P,Q,u) - \mu_T K_T(P,Q,u) - \lambda_P H_P(P,V,\theta) - \lambda_Q H_Q(Q,V,\theta)$$

The optimal solution must satisfy certain Karush-Kuhn-Tucker conditions (see [4] and [5]), that include:

$$\nabla W(P,Q,u) - \mu_G \nabla K_G(P,Q,u_G) - \mu_T \nabla K_T(P,Q,u_T) - \lambda_P \nabla H_P(P,V,\theta) - \lambda_Q \nabla H_Q(Q,V,\theta) = 0.$$

$$\mu_G K_G(P,Q,u_G) = 0,$$

$$\mu_T K_T(P,Q,u_T) = 0$$

$$H_P(P,V,\theta) = 0$$

$$H_Q(Q,V,\theta) = 0.$$

Let $P^*, Q^*, u^*, \mu_G^*, \mu_T^*, \lambda_P^*, \lambda_Q^* = \text{argmax } \{L(P, Q, u, \lambda, \mu), \ \mu \geq 0\}.$

where λ_{Pi} is the optimal real power price at bus i,
λ_{Qi} is the optimal reactive power price at bus i,
μ_{Tk} is the optimal price vector for components of transmission element k,
μ_{Gi} is the optimal constraint value vector for generator i.

The partial derivative of the objective function is usually the derivative of the cost or bid function. The Lagrange multipliers, μ, give the value of a marginal unit of the constraint and λ is the value of relaxing the conservation of power equations.

For real power at bus i,

$$\partial L/\partial P_i = \partial W/\partial P_i - \mu \partial K/\partial P_i - \lambda \partial H/\partial P_i = 0$$

Since $\partial H_{Pi}/\partial P_i = 1$ and $\partial W/\partial P_i = \partial c_i/\partial P_i$,

$$p_{Pi} = \lambda_{Pi} = \partial c_i/\partial P_i + \mu \partial K/\partial P_i + \sum_{j \neq i} \lambda_j \partial H/\partial P_i$$

For reactive power at bus i,

$$\partial L/\partial Q_i = \partial W/\partial Q_i - \mu \partial K/\partial Q_i - \lambda \partial H/\partial Q_i = 0$$

Since $\partial H_{Qi}/\partial Q_i = 1$ and neglecting losses $\partial c_i/\partial P_i = 0$,

$$p_{Qi} = \lambda_{Qi} = \mu\partial K/\partial Q_i + \sum_{j \neq i} \lambda_j \partial H/\partial Q_i$$

For voltage at bus i,

$$\partial L/\partial V_i = -\partial c/\partial V_i - \mu\partial K/\partial V_i - \lambda\partial H/\partial V_i = 0$$

$$p_{Vi} = \partial c/\partial V_i + \mu\partial K/\partial V_i + \lambda\partial H/\partial V_i$$

For reactance of transmission element k,

$$\partial L/\partial X_k = \partial W/\partial X_k - \mu\partial K/\partial X_k - \lambda\partial H/X_k = 0$$

$$p_{Xk} = \partial c/\partial X_k + \mu\partial K/\partial X_k + \lambda\partial H/\partial X_k$$

For transformer tap of transmission element k,

$$\partial L/\partial \tau_k = \partial W/\partial \tau_k - \mu\partial K/\partial \tau_k - \lambda\partial H/\tau_k = 0$$

$$p_{\tau k} = \partial c/\partial \tau + \sum_i \lambda_i \partial H_i/\partial \tau + \mu\partial K/\partial \tau_k + \lambda\partial H/\partial \tau_k$$

For shunt capacitor of transmission element k,

$$\partial L/\partial Bcap_k = \partial W/\partial Bcap_k - \mu\partial K/\partial Bcap_k - \lambda\partial H/Bcap_k = 0$$

$$p_{Bcapk} = \partial c/\partial Bcap + \mu\partial K/\partial Bcap_k + \lambda\partial H/\partial Bcap_k$$

For the thermal capacity of transmission element k,

$$\partial L/\partial MVA_k^{max} = 0$$

For the phase shifter of transmission element k,

$$\partial L/\partial \alpha = -\partial c/\partial \alpha - \sum_i \lambda_i \partial H_i/\partial \alpha = 0.$$

System Dispatch. In an ISO market or vertically integrated utility today, the transmission operators are essentially passive as market participants, with some minor active participation. Capacitors are switched in and out by the system operator. In some markets, e.g., Britain, the capacitors are mobile. In light load, transmission lines are opened to better balance reactive power. In some markets phase shifters are optimally dispatched. In others they are set as a result of a political debate. The system operator optimizes the system and returns one of the following: MVA^{max}, R, X, α, Bcap, depending on the controls to the TO and on the market design. In general, however, transmission characteristics are not changed optimally in real time.

In the reactive power market here, the system operator receives bids or cost functions in the form of the cost function along with its operating constraints from all market participants. The system operator optimizes the system and returns one of the following signals to market participants, (P, V), (p_P, P, V) or (P, V, Q), depending on the market design. When p_Q is at or near zero, the resulting signal for Q is ambiguous so the (p_P, p_Q) signal is generally unacceptable. A safe but redundant signal would be (P, V, Q, p) where (P, V, Q) should be an optimal solution to the system operator's problem and p is a vector of complete prices. Currently both OATT and ISO tariffs have penalties for not responding to quantity instructions. In ISOs the penalties are a function of the market prices. Consequently full quantity and price information may be necessary for market participants to make efficient decentralized decisions.

The above market model presents an ambitious market design to include reactive power. It is not necessary to implement all at once. Decisions on relative impact of additions to the market design should be made on a regional basis depending on the needs of the market and reliability.

The Planning Process or Forward Procurement Auctions. In the planning process or procurement auction, the system operator has different time horizon from hours ahead to a year or more. Planning activities in a vertically integrated utility require costs estimates and operating constraints from the generation and transmission operators. Procurement auctions are run by independent system operators and function by having the system operator take bids from market participants. Some auctions for capacity only and not for forward power. In these auctions constraints and rights may be defined differently. Capacity for contingencies may only be needed for short periods of time. In these cases thermal constraints can be relaxed. Active participation in these markets can be avoided with bilateral contracts, but contracts must be accounted for in the reliability constraints.

Each generator submits a bid that includes an offer for a new investment, U_{Git}, in period t, capital cost, $C(U_{Git})$, of the form:

$$b_{Gi}(P, Q, u_i) - w_{Git}C(U_{Git})$$

where $b_{Gi}(P, Q, u_i)$ is the offer/cost of operating the assets. The variable w_{Git} is a binary decision variable, representing a "yes" or "no" investment decision. The bid is subject to vector constraints:

$$K_{Git}(u_{Git}, w_{Git}, U_{Git}) = u_{Git} - U_{Git}w_{Git} \leq 0, w_{Git} \in \{0,1\} \text{ for } i = N+1, \dots, N + N^{new}$$
where N^{new} is the number of newly proposed generation investments.

These constraints are added to $K_{Git}(P, Q, u_{Git}) \leq 0$, the existing operating constraints and constraints are modified for the new investment proposals.

Each transmission operator submits a bid that includes offers for a new investment, U_{Tkt}, in period t at capital cost, $C(U_{Tkt})$, of the form:

$$b_{Tk}(P, Q, u_{Tk}) - w_{Tkt}C(U_{Tkt})$$

where $b_{Tkt}(P, Q, u_{Tkt})$ is the offer/ cost of operating the assets. The variable w_{Tkt} is a binary decision variable representing a "yes" or "no" investment decision. The bid is subject to vector constraints

$$K_{Tkt}(u_{Tkt}, w_{Tkt}, U_{Tkt}) = u_{Tkt} - U_{Tkt}w_{Tkt} \leq 0, w_{Tkt} \in \{0,1\} \text{ for } k = K+1,\ldots, K + K^{new}$$
$$\text{where } K^{new} \text{ is the number of newly proposed transmission investments.}$$

These constraints are added to $K_{Tkt}(P, Q, u_{Tkt}) \leq 0$, the existing operating constraints and constraints are modified for the new investment proposals.

We call $K_{Tkt}(u_{Tkt}, w_{Tkt}, U_{Tkt}) = u_{Tkt} - U_{Tkt}w_{Tkt} \leq 0, w_{Tkt} \in \{0,1\}$, the topology function since the setting of the w_{Tkt} defines the network. The w_{Tkt} variables are circuit breakers in dispatch markets. They collectively determine the topology of the network. In a planning model or forward markets, a circuit breaker becomes an investment option.

The system operator operates as an auctioneer by taking bids from market participants and solving a contingent AC optimal power flow. The system operator chooses a discrete set of contingencies or events that satisfy the reliability criteria for the system, e.g., N-1 contingencies. A probability, ρ_ω, is assigned to each mutually exclusive event ω where $0 \leq \rho_\omega \leq 1$ and $1 - \sum_\omega \rho_\omega$ is the probability of a system failure, e.g., 24 hours of system failures in 10 years (24/10*365*24 = .00027). An event, ω, would be a failure (forced outage) of a large generator or a transmission element.

After possible mitigation of the bids, the system operator solves the following AC optimal power flow problem:

Max $W_t(P,Q,u) =$

$$\sum_t d_t \{\sum_\omega \rho_\omega [\sum_i b_{Gi}(P^\omega, Q^\omega, u_{Gi}^\omega) + \sum_k b_{Tk}(P^\omega, Q^\omega, u_{Tk}^\omega) - \sum_i c_{Vi}(V_{it}^\omega; V_{it}^{min\omega}, V_{it}^{max\omega})]\}$$

subject to

$$K_{Gi}(P_1^\omega, Q_1^\omega, u_1^\omega,\ldots, P_{tmax}^\omega, Q_{tmax}^\omega, u_{tmax}^\omega)^\omega \leq 0, \qquad \mu_G^\omega \text{ for } \omega \in \Omega$$

$$K_{Tk}(P_1^\omega, Q_1^\omega, u_1^\omega,\ldots, P_{tmax}^\omega, Q_{tmax}^\omega, u_{tmax}^\omega)^\omega \leq 0 \qquad \mu_T^\omega \text{ for } \omega \in \Omega$$

$$H_{Pt}(P_t^\omega, V_t^\omega, \theta_t^\omega)^\omega = 0, \qquad \lambda_{Pt}^\omega \text{ for } \omega \in \Omega \text{ and t.}$$

$$H_{Qt}(Q_t^\omega, V_t^\omega, \theta_t^\omega)^\omega = 0, \qquad \lambda_{Qt}^\omega \text{ for } \omega \in \Omega \text{ and } t.$$

where d_t is the discount factor and tmax is the time horizon.

The problem is formulated as a mixed-integer nonlinear program. It requires that the system survive each contingency, $\omega \int \Omega$. Since the problem is stochastic, we can calculate expected future prices: $\underline{p}_{Pt} = \underline{\lambda}_{Pt} = \sum_\omega \rho_\omega \lambda_{Pt}^\omega$ and $\underline{p}_{Qt} = \underline{\lambda}_{Qt} = \sum_\omega \rho_\omega \lambda_{Qt}^\omega$.

Unfortunately, this problem is a large security constrained AC OPF that presents a significant computational challenge, but as a forward auction the time available to solve the problem can be measured in days.

To solve the AC optimal power flow investment auction problem, we define the Lagrangean function and we solve the optimization problem in the same manner as before. Of course, any winning bid would be guaranteed its bid costs as a payment, but as a market clearing price auction modified for two-part or multi-part pricing, more efficient compensation is possible. Where entry competition is not feasible, bids may need to be mitigated.

The auction or planning process can be designed as an iterative process. After each round market participants submit new bids to provide capacity and/or energy until the auction stops by rule or stops producing benefits. These auctions need additional rules to ensure good results.

A Possible Market Design Market. In this section we present a straw man proposal as a means of departure from current market design to stimulate discussion. The SO takes bids from generation, transmission, and load. Since the market is usually lumpy, non-convex and has low demand elasticity, market power mitigation and scarcity pricing may be necessary. The SO solves the reliability constrained AC OPF with scarcity pricing and calculates quantities (and prices if desired) for dispatch signals.

The market settlement would pay each market participant the product of bus price and quantity supplied by market participants. Other products like reserves are priced on a similar basis where the 'bus' may be an aggregated bus for each reserve category based on flow studies. An aggregate bus is an ex ante properly electrically aggregated bus that represents a region of similar electric properties. Examples include aggregations based on emergence ratings or reactive power capabilities. This is in contrast to a hub that is an ex post aggregation of prices.

Since $P_i - \sum_k P_{ijk} = 0$ and $Q_i - \sum_k Q_{ijk} = 0$, $p_{Pi}(P_i - \sum_k P_{ijk} = 0)$ and $p_{Qi}(Q_i - \sum_k Q_{ijk} = 0)$. The market is revenue adequate. If the bids are 'convex', revenue adequacy is obvious (for more details see references 8 and 9). If bids reflect marginal opportunity costs, the market result is efficient and what would result if the market is competitive.

The market settlement would also guarantee bid costs for suppliers and not charge any buyer more than they offered to pay. If the bids are not 'convex', a two-part tariff or settlement scheme may be necessary (for more details see references 10 and 11). If the ACOPF objection function is greater than zero, there is enough valued offered by buyers to compensate all offers accepted offers by the sellers. Cooperative game theory allocations have been proposed as an approach to dividing up the benefits and assigning costs, but in general, there is no single fully incentive compatible method for the second part of the tariff.

Bus prices are truly opportunity costs prices. This means that the incremental value to the market is for small changes at the bus for that time period. These prices do not give an investment signal unless the prices would persist into the future. As we have seen in the past, this is speculative

In a forward auction market with a reasonably long horizon, many market participants or potential market participants and open entry, the market is efficient and competitive. Open entry requires access to sites and right-of-way by all market participants. Each market participant has the option of bilateral contracting that will depend on the transactions costs of using or not using a central market mechanism.

An iterative auction process for long-term rights would look more like an IRP process with competition to build the new assets.

Summary. This appendix examined the investment and operating decisions for planning by a vertically integrated utility or auction markets operated by the independent system operator. For many enhancements in software the issue is the relative tradeoffs with other enhancements. Low probability events like blackouts are difficult to assess in a cost benefit analysis. Its intention is to stimulate discussion of planning, investment and dispatch markets for real and reactive power.

References:

1. Arthur R. Bergen and Vijay Vittal, *Power System Analysis*, 2nd Ed., Prentice Hall, 2000.

2. M. C. Caramanis, R. E. Bohn and F. C. Schweppe, "Optimal Spot Pricing: Theory and Practice," *IEEE Transactions on Power Apparatus and Systems*, Vol. 101, No. 9, September 1982.

3. Charles A. Gross, *Power System Analysis*, Wiley, New York, 1979.

4. David Luenberger, *Optimization by Vector Space Methods*, Wiley, New York, 1969.

5. Oliv Mangasarian, *Nonlinear Programming*, McGraw-Hill, New York, 1969.

6. William W. Hogan, "Financial Transmission Right Formulations," Harvard University, March 31, 2002, submitted to FERC in RM01-12-000.

7. Richard O'Neill, Ross Baldick, Udi Helman, Michael H. Rothkopf and William Stewart Jr., "Dispatchable Transmission in RTO Markets," *IEEE Transactions on Power Systems*, to appear.

8. R.P. O'Neill, U. Helman, B.F. Hobbs, W.R. Stewart and M.H. Rothkopf, "The Joint Energy and Transmission Rights Auction: A General Framework for RTO Market Designs," Working Paper, Office of Markets, Tariffs and Rates, Federal Energy Regulatory Commission, July 31, 2001, http://business.wm.edu/william.stewart/Energy/energy_market_economics.htm

9. R.P. O'Neill, U. Helman, B.F. Hobbs, W.R. Stewart and M.H. Rothkopf, "A Joint Energy and Transmission Rights Auction: Proposal and Properties, " *IEEE Trans. Power Systems*, 17(4), November 2002, 1058-1067.

10. Richard P. O'Neill, Paul M. Sotkiewicz, Benjamin F. Hobbs, Michael H. Rothkopf and William R. Stewart Jr., "Efficient Market-Clearing Prices in Markets with Nonconvexities," *European Journal of Operational Research*, Vol. 164/1, 269-285.

11. Richard P. O'Neill, Ross Baldick, Wedad Elmaghraby, Michael H. Rothkopf, and William R. Stewart, Jr., "Finding Two-Part Tariffs that Support Efficient Equilibria in Non-Convex Markets," August 2004, http://business.wm.edu/william.stewart/Energy/energy_market_economics.htm.

12. A. J. Wood and B. F. Wollenberg, *Power Generation Operation and Control,* 2nd Ed., John Wiley and Sons, New York, January 1996.

Electric Plants in Service (2003)

(Accounts 101, 102, 103 and 106)

Source: Form 1 Database

Accounts	U.S. Dollars
(310) Land and Land Rights	610,596,947
(311) Structures and Improvements	15,183,125,395
(312) Boiler Plant Equipment	63,984,610,251
(313) Engines and Engine-Driven Generators	118,645,023
(314) Turbogenerator Units	18,138,116,901
(315) Accessory Electric Equipment	7,747,563,668
(316) Misc. Power Plant Equipment	2,031,368,371
(317) Asset Retirement Costs for Steam Production	256,278,453
TOTAL: Steam Production Plants	**108,070,305,009**
(320) Land and Land Rights	189,393,277
(321) Structures and Improvements	20,634,123,933
(322) Reactor Plant Equipment	30,382,418,886
(323) Turbogenerator Units	9,375,167,934
(324) Accessory Electric Equipment	9,626,506,240
(325) Misc. Power Plant Equipment	4,151,263,843
(326) Asset Retirement Costs for Nuclear Production	3,700,054,774
TOTAL: Nuclear Production Plants	**78,058,928,887**
(330) Land and Land Rights	499,961,476
(331) Structures and Improvements	2,072,478,124
(332) Reservoirs, Dams, and Waterways	6,352,487,660
(333) Water Wheels, Turbines, and Generators	2,979,902,854
(334) Accessory Electric Equipment	824,581,003
(335) Misc. Power Plant Equipment	255,842,689
(336) Roads, Railroads, and Bridges	190,436,253
(337) Asset Retirement Costs for Hydraulic Production	15,725,473
TOTAL: Hydraulic Production Plants	**13,191,415,532**
(340) Land and Land Rights	120,149,148
(341) Structures and Improvements	1,933,732,229
(342) Fuel Holders, Products, and Accessories	1,163,672,943
(343) Prime Movers	8,215,313,643
(344) Generators	7,639,307,657
(345) Accessory Electric Equipment	1,600,073,967
(346) Misc. Power Plant Equipment	220,264,209
TOTAL: Other Production Plants	**20,892,513,796**

Application of AEP Methodology to all the respondents of Form-1

Accounts	U.S. Dollars
TurboGen Accounts	
314	18,138,116,901
323	9,375,167,934
333	2,979,902,854
344	7,639,307,657
Total	**38,132,495,346**
Accessory Electric Equipment Accounts	
315	7,747,563,668
324	9,626,506,240
334	824,581,003
345	1,600,073,967
Total	**19,798,724,878**
All Production Plant Accounts 310-346	
Steam	108,070,305,009
Nuclear	78,058,928,887
Hydro	13,191,415,532
Other	20,892,513,796
Total	**220,213,163,224**
Total costs of Turbogenerator	38,132,495,346
Percentage of Cost allocated to Generator and Exciter	24%*
Cost of Gen+Exciter	9,151,798,883
Total costs of Accessory Electric Equipment	19,798,724,878
Percentage allocated to VAR production	10%*
Cost of Accessory elctric equipment - watt/var production	1,979,872,488
Total (Gen+Exciter+Accessory electric equip)	11,131,671,371
Percentage allocated to Reactive Power	21%*
Investment in Reactive Power Production	2,337,650,988
Production Plants - (Gen+Exciter+Accessory Electric equip)	209,081,491,853
Percentage of real power reqd to produce reactive power	0.15%*
Investment in Reactive Power Production	313,622,238
Total Investment in Reactive Power Production	2,651,273,226
Percentage allocated to reactive power production	1.2%

These percentages were used in American Electric Power Service Corp., 88 FERC P61, 141 (1999)

FEDERAL ENERGY REGULATORY COMMISSION

Principles for Efficient and Reliable

Reactive Power Supply and Consumption

888 First Street, N.E. Washington, D.C. 20426

STAFF REPORT

Docket No. AD05-1-000

February 4, 2005