Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT

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Executive Summary

Electricity markets employ open access and non-discrimination to foster competition, market entry, and innovation. The physical characteristics of the electricity system require explicit consideration of key elements in electricity market design. Pricing and settlement rules for the real-time market must provide efficient incentives, both for short-term operations and long-run investment. The ERCOT energy-only market design emphasizes the need to get the real-time prices right. The recent innovation of the ERCOT Operating Reserve Demand Curve (ORDC) addressed the fundamental problem of inadequate region-wide scarcity pricing that has plagued other organized markets, which have exhibited inadequate incentives both for reliable operations and efficient investment.

ERCOT employs an open wholesale electricity market as the basis for short-term reliable electricity supply as well as for long-term investments to maintain reliability in the future. A review of energy price formation in ERCOT leads to two important conclusions: (i) while the ORDC is performing consistently within its design, scarcity price formation is being adversely influenced by factors not contemplated by the ORDC; (ii) other aspects of the ERCOT market design must be improved to better maintain private market response to energy prices as the driver of resource investment, maintenance expenditure and retirement decisions.

The paper identifies three general issues that have affected ERCOT energy prices in recent years, and recommends policy and price formation improvements consistent with efficient market design. These recommendations cannot reverse the impact of broader economic trends, such as low natural gas prices, or national policies, such as subsidies for investments in renewable resources. However, the stress of these forces has exposed areas where there is a need for adjustments to pricing rules and policies within ERCOT.

System-wide Price Formation

- **Marginal Losses:** The efficiency of region-wide prices in ERCOT is distorted by the omission of the marginal cost of transmission losses from ERCOT's energy market dispatch and pricing.
- **ORDC Enhancements:** The system-wide ORDC calculation should be enhanced to address the reliability impacts of changes in the generation supply mix and the price impacts of reliability deployments.

Locational Scarcity Pricing

- **Out-of-Market Actions to Manage Transmission Constraints**: Local scarcity pricing and mitigation rules require changes to properly set prices when there are reliability unit commitments or other ERCOT reliability actions to manage transmission constraints; these changes should not disable rules for local market power mitigation.
- **Dispatch and Pricing for Local Reserve Scarcity:** Introduction of local reserve requirements, implemented through co-optimization of the energy dispatch and reserve schedules, would provide a market solution to properly set prices when there are constraints on reserve availability in a sub-region.

Transmission Planning and Cost Recovery

- **Transmission Planning:** Market-reflective policies for transmission investment should be considered as a replacement for Texas' socialized transmission planning, which, by building new transmission in advance of scarcity developing, fails to provide the opportunity for markets to respond.
- **Transmission Cost Recovery:** Alternatives for transmission cost recovery to replace or reduce dependence on the summer peak demand-based mechanism for the allocation of sunk transmission costs would reduce distortion of energy market pricing.

An Appendix provides further details on a formulation and computational approach for calculation of co-optimized prices for energy and operating reserves with local reserve requirements.

Table of Contents

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Introduction

The Electric Reliability Council of Texas (ERCOT) employs an open wholesale electricity market as the basis for short-term reliable electricity supply as well as for long-term investments to maintain reliability in the future. Texas introduced wholesale market competition in 1995, and retail competition was subsequently implemented in 2002 under the requirements of Senate Bill 7 of 1999. This was followed by the Texas Nodal reforms of 2008, which instituted the existing market structure in 2010. These initiatives were intended to open the market to competition, allow voluntary decisions about purchases and sales of electricity, and avoid imposing excessive risk of resource expansion on consumers. The success of the Texas effort has been widely recognized. The Public Utility Commission of Texas (PUCT) has been charged to continue the improvement and efficiency of this enterprise to support markets and competition. As reported by the Commission, "the competitive market has produced average retail rates that consistently trend lower than those seen in other parts of the country in all sectors" (PUCT, 2015).

The ERCOT market is an advanced example of an unbundled and restructured electricity market run by an Independent System Operator (ISO), with competition at both the wholesale and retail levels. A major innovation in ERCOT was the adoption of an Operating Reserve Demand Curve (ORDC), in June 2014, as part of a continuing effort to improve the relationship between electricity market prices and the underlying cost of reliable electricity supply. Electricity suppliers in ERCOT receive direct compensation only from short-term energy markets, without additional revenue from a separate organized forward capacity market. Market participants can arrange voluntary longer-term bilateral contracts to support investments and hedging, but the incentives for these transactions depend critically on getting the prices right in the short-term energy markets. Hence, payment for the provision of operating reserves and energy during short-term periods of scarcity through the ORDC is a critical element of the ERCOT market design to support reliability.

In October 2015, the PUCT launched a review of the performance of the ORDC to date and of possible design changes to this innovation in electricity pricing.[1] Modifications to the ORDC would be important in their own right, and would also be a gateway to improvements in other related features of the broader wholesale market design.[2] As a contribution to the review process, the present paper addresses possible changes in the ORDC, as well as other opportunities to improve price formation in ERCOT's wholesale market design as a signal of the underlying cost of maintaining reliability. Among the challenges facing the market are those arising from increasing energy supply from subsidized renewables, as well as continuing challenges, such as transmission investment and cost recovery, and the persistent lower cost of the wholesale market's marginal fuel (i.e. natural gas), which results in lower energy and ancillary service revenues.

Lower natural gas prices and the proliferation of renewables in ERCOT have changed market fundamentals and transformed the balance sheets of electricity generation owners in the region. These changes in fundamentals cannot be reversed, nor is it the purpose of good market design to attempt to reverse the fundamentals or unwind what is already done. But, just as one would be concerned about high prices, persistent pressure on pricing outcomes motivates an examination of whether the market design and price formation rules in ERCOT could be improved in support of greater efficiency and sustainable electricity markets.

A primary motivation for this review was an assessment of the operation of the ORDC. A broad conclusion is that over the more than two years since implementation, operation of the ORDC has been consistent within the context of its basic design. However, it is also evident that there are factors external to the ORDC that are influencing scarcity prices and price formation in a meaningful way. In regards to specific ORDC performance, there have been periods of operating scarcity and corresponding higher energy prices, but the average effect of ORDC on prices has been small. This result is consistent with the high operating reserves used as inputs to the ORDC. A closer examination reveals impacts on supply and demand which often inflate reserves and suppress ORDC price adders. In short, the ORDC is working within the context of its design, but it is influenced by numerous external factors and it has not been severely tested.

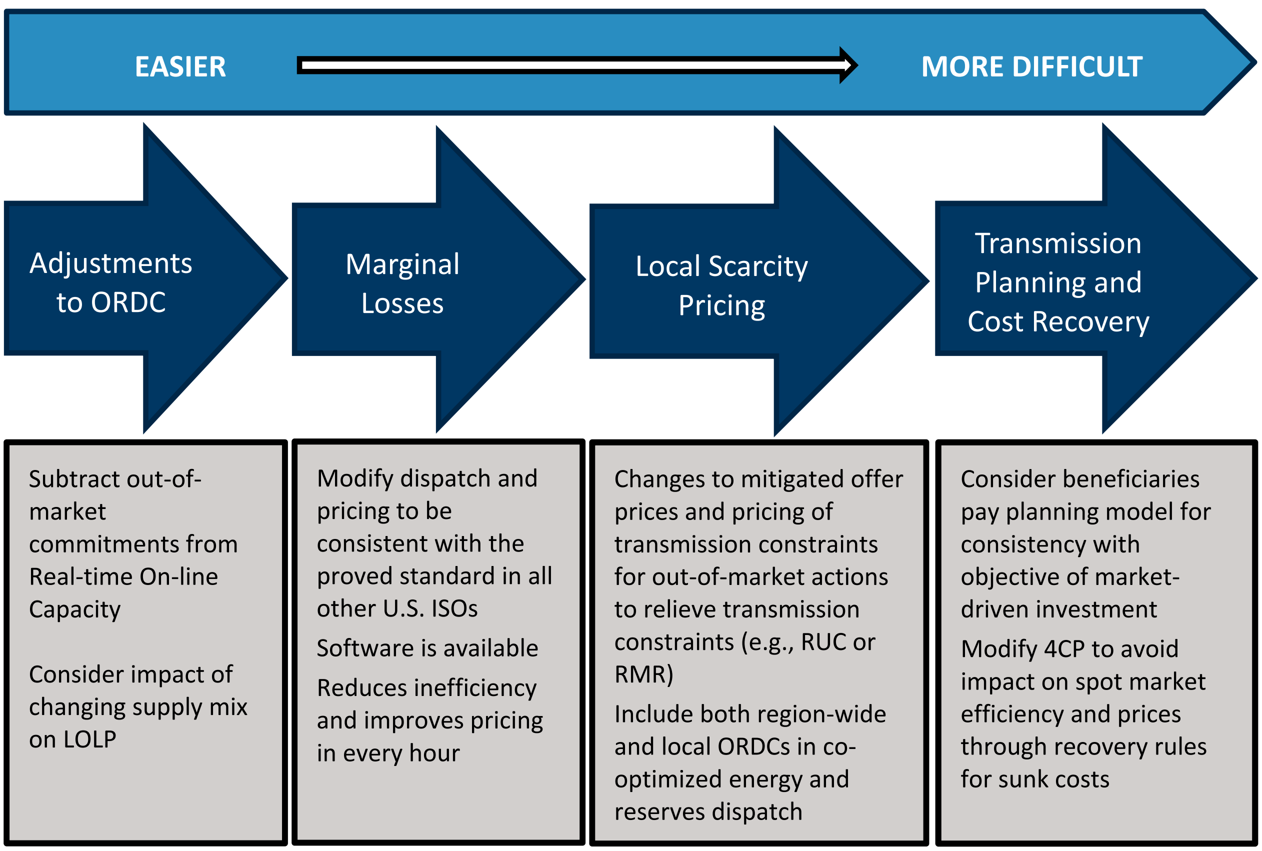
Figure 1 summarizes our recommendations for price formation reforms in ERCOT. The current design of the ORDC incorporates simplifications and assumptions that could be revisited. The present paper considers possible modifications to the minimum reserve level "X", the value of lost load, the loss of load probability, and the calculation of available reserves. With regard to

[1] PUCT Project 45572, "Review of the Parameters of the Operating Reserve Demand Curve," launched at the Open Meeting of October 8, 2015.

[2] Bryant, Mark, Julia Harvey and Jason Hass, PUCT Memorandum, "PUCT Project 45572--Review of the Parameters of the Operating Reserve Demand Curve," April 1, 2016.

the current ORDC implementation, improvements to price formation appear possible through the modification of the loss of load probability to take account of the uncertainty accompanying high levels of intermittent resource output, and logical modifications to exclude the capacity of out-of-market deployments from the estimate of reserves.

Figure 1
Price Formation Reforms



In reviewing the performance and extensions of the ORDC, other critical elements of the ERCOT market design arise as issues on their own merit. The lack of marginal-loss pricing creates a persistent distortion in locational prices and in the real cost of serving load. A marginal-loss price component could accumulate to have an effect on locational prices of the same order of magnitude as the effect of marginal congestion, which is included in both dispatch and pricing. Reliability constraints can create perverse conditions when they induce out-of-market actions, such as reliability unit commitment, that, in combination with market power mitigation, result in lower, not higher, market prices.[3] Finally, out-of-market transmission planning and

[3] The Appendix presents a formulation for the co-optimization of energy and reserves that includes the computation of local scarcity prices to complement the region-wide ORDC in order to begin to correct the lack of market-based alternatives for responding to local reserve scarcity conditions

expansion occurs ahead of the development of scarcity and diminishes the scarcity price signals that would lead, in the alternative, to market-based investment. Furthermore, the allocation of sunk transmission costs based on peak period usage leads to price suppression as well as welfare loss as market loads make expensive decisions to avoid allocations of sunk transmission costs that cannot be avoided in the aggregate.

Addressing these market design issues should be part of the continuing PUCT and ERCOT agenda for getting the prices right. The discussion below addresses these related issues under the general grouping of system-wide pricing matters, local requirements and scarcity pricing, and transmission planning and cost allocation.

The background for all this discussion begins with the basic electricity market design framework. Before addressing the possible reforms, the next section summarizes the foundations that drive the ERCOT energy-only market design for reliable and efficient operations supported by a compatible system of efficient prices.

Foundations

The design of the Texas electricity market embraces the principles of open access and non-discrimination. The underlying premise of this approach is that if all market participants have comparable access to the inherently monopoly elements of the electricity system, namely the transmission and distribution systems, then they can compete on a level playing field to buy, sell, and trade energy and thereby achieve economically efficient market outcomes. Because of the complexity of the electricity system, with the underlying engineering reliability requirements interacting with the physics of how power flows from supply sources to load sinks, the electricity sector is unique in comparison to seemingly similar markets, such as for gas supply, in the requirement for some significant degree of central coordination in support of this open access (Hogan, 1992).

After much debate and several false starts, a model has emerged for how a centrally-organized electricity market can be designed to provide open access and non-discrimination in pursuit of economically efficient operation and investment. A key requirement is for an efficient real-time market design, which is important in its own right, and also because the expected prices in the real-time market provide the basis for investment and contractual decisions in forward time periods. Market participants will anticipate real-time conditions and make forward decisions, such as investing in new plants or signing contracts for future delivery, which recognize the market determinants of real-time prices and associated settlement payments. A well-functioning real-time market will encourage efficiency in investments and other business arrangements in forward markets. Conversely, if real-time prices are not consistent with the basic practices of operators to maintain efficient and reliable electricity system operation, market participants will identify profitable opportunities to exploit the predictable inconsistencies and the actions that system operators will need to take to maintain reliable operation. The resulting inefficiency and threats to reliability can in turn lead to pressures to restrict access or discriminate among market participants in order to prevent unintended outcomes or an unravelling of the intended market (Hogan, 2002). A good real-time market design with efficient prices should be the first focus of an organized wholesale electricity market.

The following sections describe the foundational elements of efficient electricity market design, to serve as a touchstone for assessing the impact of factors that could undermine price formation and also of possible improvements. The core features of the ERCOT market design reflect these elements, but the presence of factors that frustrate price formation is apparent. The opportunities for improvement of this design are important, but should build on, rather than replace, what Texas has already accomplished.

REAL-TIME WHOLESALE MARKETS

The overarching market design framework for real-time markets follows the structure of a bid-based, security-constrained economic dispatch. Market participants provide the system operator with schedules for energy transactions from generation and load, including bids and offers to change load and generation from any announced schedules. This can include bids and offers made independently of any formal schedule. The system operator treats these bids and offers as representing the best estimate of variable costs, and chooses the dispatch (i.e., the schedules for load and generation in an interval) that reflects the physical operating and security constraints in the system, as well as any announced schedules, and maximizes the sum of the net benefits defined as the value of the scheduled load as expressed by the bids and the cost of the scheduled generation as expressed by the offers. In the absence of price-responsive demand, the dispatch simplifies to minimization of the generator offer cost of meeting a fixed level of forecast load.

The term-of-art for this structure is “economic dispatch” and the industry has been using this principle for efficient electricity system operations since long before the creation of open-access electricity markets. The innovation for markets was to price the real-time schedules determined in the economic dispatch according to the conditions of the economic dispatch, including the impact of transmission congestion and marginal losses. Security constraints and transmission power flows can sometimes create significant congestion in this system. Marginal line losses also determine the cost of moving power from one location to another. The result is a system-wide set of prices that differ by location in the system, often known as locational marginal prices (LMP). An LMP is the marginal cost of serving an increment of load at a location on the system from available supply, including the marginal cost due to transmission congestion and line losses. These LMPs are the only prices that are consistent with the economic dispatch. The meaning of this consistency is important: in the idealized case, if generation at the location is paid according to these prices, then there is no economic incentive for the generation to produce a level of output in an interval differing from its economic dispatch schedule. Similarly, if load is charged these prices, there is no economic incentive for the load to consume a different quantity in an interval than the efficient economic dispatch outcome. In this sense, the LMP prices are the only prices that can lead market participants to voluntarily transact in alignment with the efficient market dispatch outcome; the payment of the price is sufficient, without the need for side payments, penalties, or other rules. This “is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments” (International Energy Agency, 2007).

The real-time market with LMP pricing creates the opportunity to solve the difficult problem of defining and implementing transmission rights in the electricity system. Although it is not possible to define or use transmission rights to control the actual flow of power because of the complex interactions in the power flows, it is possible to define a financial contract that provides the needed complement to contracts for energy defined at a location and priced based on LMPs. The financial transmission right, known as a Congestion Revenue Right (CRR) in ERCOT, entitles the holder to collect the congestion price difference between two locations (Hogan, 1992). Like a physical transmission right, market participants can buy CRRs between two locations to effectuate a contract to buy power at one location for delivery or consumption at a second location without net payment of a real-time transmission charge.

The basic design of bid-based, security-constrained, economic-dispatch with locational prices and financial transmission rights has been adopted by all the organized markets in the United States, including ERCOT. The lessons of the failures along the way were expensive (Hogan, 2002), but the failures reinforced the basic message about the importance of the fundamental elements of the design.

Although there would be efficiency gains from operating an electricity system with only a real-time LMP market, a common feature of electricity markets is to extend the design to include one or more forward markets, such as the day-ahead organized market, as well as markets for ancillary services. These arise because electricity market operating decisions include choices which are necessarily discrete, such as forward unit commitment decisions. Extensions of the market design also arise because electricity market outcomes are affected by and invoke trade-offs in consideration of long-term investments, such as major transmission line expansions, that must invoke additional pricing and cost-recovery decisions. The details of the design extensions described in the following sections depend on the particular region, but the essential principle is for the design to result in outcomes as consistent as possible with the choices that would result from the operation of an efficient market.

DAY-AHEAD WHOLESALE MARKETS

The design of day-ahead wholesale electricity markets reflects the need for compatibility with the real-time market. The day-ahead market includes the same basic framework of bids and offers for energy. The resulting economic dispatch produces day-ahead locational prices and the associated day-ahead load and supply dispatch schedules. The day-ahead market is settled at the day-ahead locational prices and creates a set of short-term forward contracts, i.e., contracts to inject or withdraw the day-ahead scheduled quantities in real-time, or pay real-time prices for deviations.

The day-ahead market provides increased flexibility for scheduling load and generation. Given an efficient real-time market, day-ahead market designs can accommodate both physical and financial decisions and evaluate them in respect to transmission constraints on power flows and other constraints to insure reliability. Unit commitment and related physical decisions are made day ahead in the context of efficient forward trading of energy, resulting in day-ahead settlements providing price certainty for entities making discrete operating decisions in the day-ahead time frame. Unlike unit commitment, before real-time, energy trading is essentially a financial transaction. Forward agreements to buy or sell energy in real-time will be settled with real-time deviations between the real-time dispatch and day-ahead schedules priced at the efficient real-time prices. This allows day-ahead and other forward markets to include so-called “virtual” bidders that work through financial contracts, driving equilibrium in prices between forward markets and the expected prices for the real-time physical dispatch. Because forward markets for energy do not involve physical delivery, they can include a wide array of virtual participants, improving market liquidity for physical loads and generation and reducing the potential for any exercise of market power by increasing the number of market buyers and sellers (Hogan, 2016).

With the introduction of a day-ahead market in addition to a real-time market, the day-ahead prices are used to settle the CRRs in the day-ahead market; the CRRs are not settled in the real-time market. In effect, the CRRs are reconfigured in the day-ahead market as transmission schedules for the real-time market. This precludes settling the CRRs at real-time prices, which would amount to selling the transmission capacity twice. However, any market participant that wishes to settle its CRRs at real-time prices can do so by submitting Point-to-Point (PTP) Obligation bids into the day-ahead market. Awarded PTP bids are day-ahead schedules, for which the market participant will be charged the day-ahead prices, with the congestion component covered by the day-ahead settlement of its corresponding CRR. The CRR is thus reconfigured into a day-ahead transmission schedule conveying the real-time obligation to buy power at one location for delivery or consumption at a second location without payment of a real-time transmission charge.

This basic structure adapts to account for any sequence of forward markets. For example, with day-ahead and then hour-ahead markets, at each stage the forward dispatch with associated locational prices creates a set of contracts that could be settled at the prices in the subsequent stage.

Again, in the idealized case, all that would be required to ensure efficient operations and investment is the day-ahead market functioning based only on competition through bid-based, security-contained, economic-dispatch with locational prices and financial transmission rights. But complications arise because of deviations from the assumptions of the idealized case. In particular, unit commitment decisions can be large enough to have a non-marginal effect on prices and require some intervention to deal with the differences from the pure marginal cost pricing case (Gribik, Hogan, & Pope, 2007). Similarly, the system operator may need to commit some units to meet reliability constraints (i.e. Reliability Unit Commitment) that may not be represented in the dispatch model.

These types of decisions can create a deficiency in the LMP revenues paid to suppliers compared to the full offer-based costs they would incur to produce their least cost dispatch schedules. For pricing, this deviation creates an essential requirement to combine reasonable approximations of prices based on pure marginal costs and marginal benefits with related additional payments needed to maintain the incentives of load and generation to follow their dispatch schedules. For example, generators committed in the day-ahead dispatch may not recover their full start-up costs through only the LMPs paid for their energy injections. The revenue deficit would provide an incentive to not participate in the dispatch. But additional payment of the deficit in addition to the marginal energy price can restore consistency between the total revenue the generator receives and the cost it incurs when it follows its dispatch schedule. These are known as “make-whole” payments because they must be recovered through an additional charge on top of the price for energy to ensure a generator’s revenue is at least equal to its offer costs.

ANCILLARY SERVICES

The idealized energy market design often abstracts from elements of operations that are necessary for secure operation of the transmission grid and the rest of the electricity system. These added services deal with a variety of requirements that are relatively small scale, compared to the total energy flow, but are essential for maintaining reliability, efficiency, and compliance with mandatory national standards.

For example, fast standby reserves must be available for quickly responding to unanticipated forecast deviations or contingency events. Sudden loss of a generator must be addressed quickly by increasing output from other generators or decreasing load. The standby resources provide operating reserves necessary to meet the fast response reliability requirements of the system.

Operating reserves and other services go under the general heading of ancillary services. The fundamental market design principle is to dispatch and price these services in a manner that is consistent with the basic market design and avoids significantly changing other efficient incentives for energy load and generation.

Application of these principles to the case of operating reserves illustrates the point through the development of the ERCOT ORDC, as discussed below.

MARKET POWER MITIGATION

With competitive price-taking market participants, individual operating decisions can be left to respond to the incentives of the efficient real-time and day-ahead prices. When there are market conditions during which some market participants can manipulate prices, interventions may be required to prevent such strategic behavior and ensure efficient outcomes. The objective is to design market power mitigation mechanisms to make them compatible with the basic efficient real-time and day-ahead wholesale markets.

Market participants may exercise market power in their bids and offers for a subset of transactions to manipulate prices and profit from related transactions. The canonical example is the case of a large generator that can withhold some of its production, increase the market-clearing price, and enjoy higher prices on the portion of its generation that is not withheld. If prices can be increased enough, then the increased profits on the actual production could be sufficient to outweigh the loss on the withheld supply. The result would include higher prices for load and higher total real costs for the dispatch.

As a condition for participating in the organized electricity markets, regulations typically provide mechanisms for mitigating or preventing the exercise of market power. The example of the large generator provides a convenient illustration of the principle of designing the market intervention to be as consistent as possible with the overall efficient market design.

An initial response to mitigate market power is often to place a cap on the market price outcome, thereby preventing the increase in market prices that would be sought by a supplier seeking to profit from exercising market power. However, this price cap could create unintended consequences if not set at the right level to reflect actual operating conditions and system-wide or local scarcity in the real-time market.

An alternative approach developed early in electricity markets is to impose an offer cap for capacity with the potential for exercising market power, in place of a price cap for everyone. The offer cap is combined with a must-offer requirement to avoid physical withholding of supply. The purpose of an offer cap is to insure the capacity offered is made available for dispatch at a reasonable estimate of the variable cost of the generator plus a reasonable risk factor considering current operating conditions. In the actual dispatch, the market-clearing price may be much higher than the offer, and may well be higher than would be accommodated by a price cap. But even if the price rises above the offer cap, as long as the offer cap is in place, the generator is not exercising market power, and the generator would be paid according to the market-clearing price, not the offer cap. The offer cap only determines if the generator is dispatched, but not what it is paid as the market-clearing price. If there is an effective mechanism for determining the market-clearing price, then the result is the same as the competitive outcome without the exercise of market power. This offer-cap approach to market power mitigation sounds similar to a price cap, but it is fundamentally different. The offer-cap approach arises from close consideration of how to design a regulatory intervention that incorporates and better reflects efficient market design. The existing ERCOT market power mitigation approach uses offer caps as a primary tool, and even exempts small generators ("small fish swim free") who presumably cannot affect the system-wide market price and would not physically withhold their generation due to the risk of having a portion of their portfolio not committed.

INFRASTRUCTURE INVESTMENT

Under the basic competitive electricity market design, investment decisions for generation and load are left to the decisions of market participants based on their own evaluation of future market prices and opportunities. This is a critical component of the energy-only market approach in ERCOT.

Investments in other types of infrastructure present complications for efficient market operations, as they may affect the efficient energy market price signals that are the linchpin of the basic market design. For example, transmission investments can preempt more economic market solutions for reliably serving load and have a material effect on market prices. This complicated problem is created by a regulatory structure where transmission investments are generally made mandatory, often planned through processes that are not well integrated with those focused on the sustainability of efficient electricity markets, and receive a guaranteed rate of return. Market investments by suppliers or loads are expected to compete with transmission investments receiving rate-base returns. The design of investment policy for transmission that supports efficient markets is a challenge in all existing energy markets.

An important characteristic of open markets and competition is the role of voluntary choices in the purchase and sale of power. Market participants are responsible for and bear the costs of their decisions; conversely, they should not be subject to cost responsibility for resource investments where they have little or no control over the decisions. This market discipline is relatively easy to maintain for load and generation, where the costs and the benefits flow to those who make the consumption and investment decisions.

Transmission investment is perhaps the most difficult element to cover under the principle of structuring the rules to result in choices that are as close as possible to the efficient outcomes that would result from competition within the underlying market design, and then handling the rest of the market intervention in ways that have the least impact on efficient market choices. However, the logic still applies in the transmission case. This is best illustrated by the approach in the New York tariff (NYISO, 2007);(Hogan, 2011), which follows this principle.

The essence of the New York approach is to balance market incentives and the need for regulation to deal with large scale transmission projects that can give rise to free-rider concerns. Market participants can make transmission investments as merchant investments that depend on future market revenues to finance the project. The revenues could come in the form of voluntary *ex-ante* contracts between transmission developers and generators that benefit from higher prices and loads that benefit from lower prices; an additional revenue source for transmission development could be future CRR revenues. This works well for small projects where enough of the beneficiaries can collaborate and the beneficiaries voluntarily pay for the project, so long as the contractual payments are not a loss-taking attempt to exercise market power. For large projects that affect many beneficiaries, this merchant approach may not work because there are too many “free riders,” which is a situation in which parties do not voluntarily offer to pay a share of the project costs commensurate with their individual benefits with the hope that others will pay and they will be able to reap the benefits without paying any costs. Here the regulator must intervene to evaluate costs and benefits. When the benefits are greater than the costs, the project should be able to command enough support to sustain a supermajority vote of beneficiaries who favor the project. The votes are weighted in proportion to the estimated benefits and if a supermajority is obtained, the transmission project goes forward and all the beneficiaries pay for the costs of the project in proportion to their deemed benefits. The payment is not voluntary for any in the minority that opposed the project. In the event that a supermajority of the beneficiaries cannot be obtained, the project fails the market support test and does not go forward. In all cases, those who do not benefit do not pay, and do not vote. Involuntary payments for transmission investment are required in the limited case only to deal with free-rider concerns for a small minority of the beneficiaries.

The issue of the appropriate approach for infrastructure investment will be important on the national agenda where major transmission expansions are a subject of continuing discussion (Department of Energy, 2017). The major recent investments for transmission expansion in ERCOT are sunk, but the manner of the cost recovery may impact current decisions, and future developments may raise the profile of transmission investment decisions and the interaction with efficient market design. Costs socialized across all market participants undermine efficient incentives and should be avoided whenever possible.

GETTING THE PRICES RIGHT

Subject to this fundamental framework, the challenge is to design the necessary additional market features to be as consistent as possible with the efficient market design and to minimize any distorting effect on future efficient decisions (Hogan, 2014). This in itself can go a long way to support the energy-only approach as found in ERCOT including the factors currently impacting price formation. The discussion of the design of the ORDC illustrates a practical application of this principle.

ERCOT Energy-only Market

In the early phase of unbundling and creation of an organized electricity market, ERCOT deployed a zonal model based on the assumption that locational differences in marginal costs of incremental electricity supply or demand within a zone would be unimportant and could be ignored. During periods when this assumption proved to be materially incorrect in ERCOT, as elsewhere, the market pricing design created perverse incentives inconsistent with the management of system reliability and soon became unsustainable. The response was to implement a fully nodal model in ERCOT using the essential elements of bid-based, security-constrained, economic dispatch (Potomac Economics, 2011).

Although this major reform implementing nodal pricing addressed the most serious of the perverse incentives of the earlier zonal market design, the ERCOT market eventually developed evidence of an implementation problem in pricing during scarcity situations; similar issues were observed in other ISOs. Although the basic design worked well when the system was not stressed, in most markets a wide variety of implementation details combined to suppress prices when systems encountered a scarcity of supply to meet either regional or local demand (Joskow, 2008). Examples of these details include price caps, uneconomic out-of-market reliability actions, uneconomic reserve requirements, the treatment of block-loaded quick start units in price formation, and the absence of demand participation. The result was the "missing money" problem wherein electricity prices did not rise high enough and often enough to support economic investment in generating capacity and required maintenance of existing supply.

PERSISTENCE OF MISSING MONEY

The underlying theory of the original market design included demand participation through bidding by load of its willingness-to-pay. During periods of supply scarcity, when capacity was fully utilized, prices would rise and demand would voluntarily reduce to clear the market. In these capacity constrained periods, demand would set price and the price could be materially higher than the variable cost of the most expensive plant running. Within this framework, the price effect would be adequate to support economic investment and there would be no missing money.

For a variety of reasons, including interventions to mitigate price increases, this demand participation did not appear, and is still developing slowly. The biases summarized by Joskow continued to hold sway to keep market prices low. The resulting missing money problem affects the incentives for new generation investment, retirement and maintenance and was identified as a threat to resource adequacy. A policy response in many other markets was to develop various forward capacity market options to provide a mechanism for making additional payments for capacity to support adequate investment.

The turn to capacity markets would have been a major change in the ERCOT policy to maintain an "energy-only" market design. When the missing money issue became salient in ERCOT, the response was to review the experience with capacity markets elsewhere and to look for options that could preserve the energy-only market design (Newell et al., 2012). The ERCOT approach would address the pricing problems directly by making important changes in the nodal market design to produce pricing incentives sufficient to maintain reliability. The most significant innovation was the treatment of scarcity pricing through the introduction of an ORDC that would help mitigate the effect of the missing demand participation.

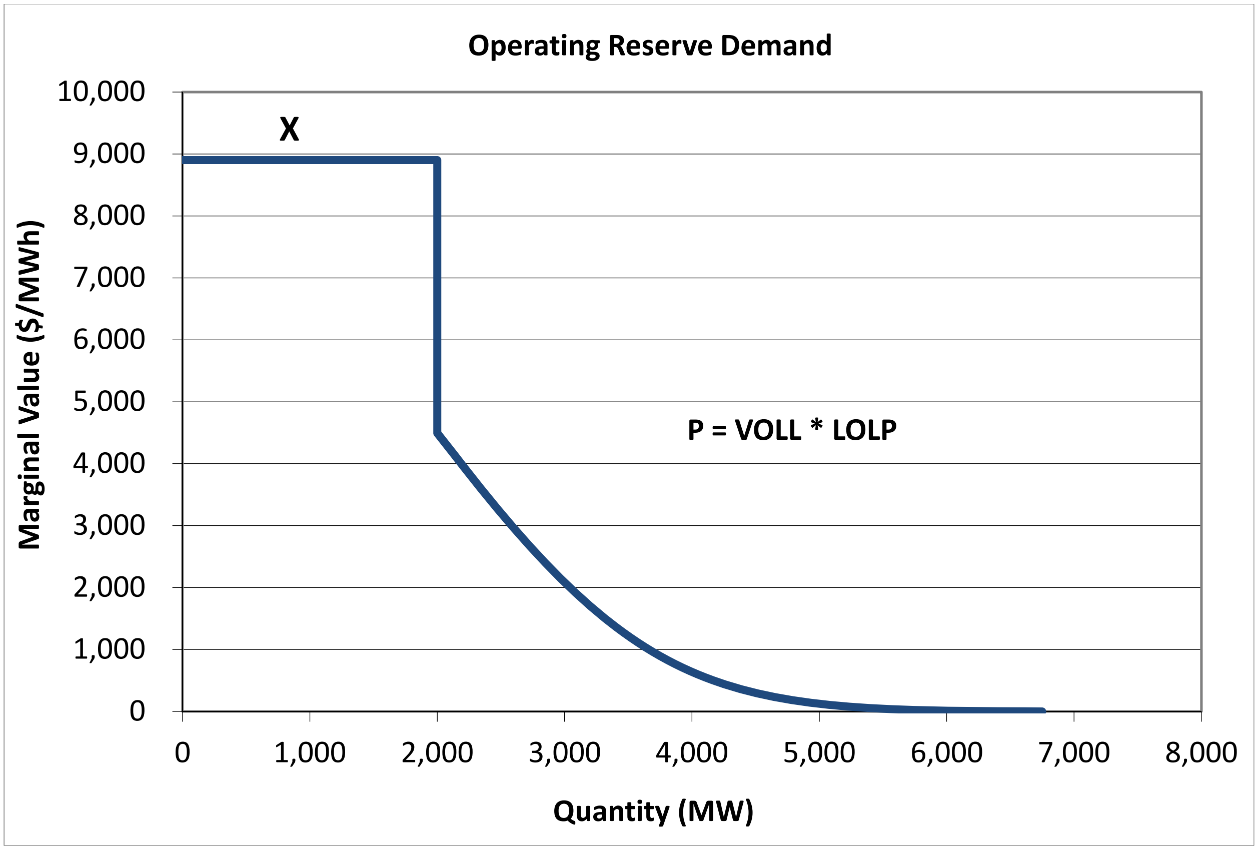
OPERATING RESERVE DEMAND CURVE

The ERCOT implementation of an ORDC illustrates the importance of carefully considering the interactions among the basic components of the successful market design in order to respect the fundamental principle of getting the prices right.

The theory of efficient electricity market design, which is the starting point for the ORDC, focuses on the dispatch and pricing of energy supply and demand. Other ancillary services could be included in the basic design, but were usually addressed in a simple way. Operating reserves were a case in point prior to the ORDC. The basic model assumed a fixed requirement for operating reserves. Optimization of schedules for suppliers (and possibly dispatchable load) in the security-constrained economic dispatch produced a related scarcity price if this fixed requirement for operating reserves was an active constraint on the dispatch. The scarcity price rose as more expensive supply or demand resources had to be dispatched in order to maintain the required levels of operating reserve. For instance, if price-responsive demand was deployed in the dispatch because the price rose above its bid (i.e., its willingness-to-pay), these demand-side bids would set both a high energy price and a high implied scarcity price for operating reserves when the system was stressed.

Absent material demand-side participation, ERCOT reconsidered the treatment of operating reserves, rather than creation of a capacity market, to address the missing money arising from energy-only pricing. Rather than treating operating reserves as a fixed requirement, where reserves above the minimum amount would have zero value, it recognized that in electricity system operation there is an underlying scarcity value to reserves at levels above this minimum amount. The scarcity value of operating reserves of differing levels could be calculated and included along with electricity supply and demand in the economic dispatch. The relationship between scarcity value and reserve levels, i.e., the ORDC, incorporates a more granular estimate of the willingness-to-pay to meet operating reserve reliability requirements and produces a market-clearing scarcity price that reflects the value of remaining operating reserves.

Figure 2



The ERCOT ORDC shown in Figure 2 combines two types of operating reserve requirements. The minimum quantity of reserves required for system security, represented by "X", is a limit that is the minimum allowable MW to meet the standards defined to avoid cascading system failures. In principle, if the level of operating reserves starts to fall close to this limit, the system operator should curtail load in order to preserve the necessary reserves. Hence, at this minimum reserve level, the marginal value of operating reserves would be the same as the value of lost load (VOLL), since a 1 MW increment in reserves would prevent the shedding of 1 MW of load.

Above this minimum level of reserves, X, which is 2,000 MW Figure 2, the economic value of incremental operating reserves falls. Above X, the system operator will not be actively shedding load, so the value of operating reserves depends on the probability that this might happen, i.e., the probability that the system will move into the condition where reserves would be less than the minimum required. For the range above X, the value of incremental reserves is equal to the loss of load probability (LOLP) multiplied by the value of lost load. This basic LOLP relationship is familiar from traditional industry planning models, with the added modification of the need to respect the minimum contingency limit (X).

In a full implementation, the ORDC would be included in the normal real-time energy dispatch and co-optimization of energy and reserves and would create a scarcity price, i.e., the marginal price of operating reserves. When the marginal cost of dispatching additional reserves was less than the marginal value in avoiding a loss of load, where the latter is as expressed by the ORDC, additional reserves would be dispatched. When the cost of incremental reserves rose above the incremental value, less would be dispatched. Because a MW of most capacity can supply either energy or reserves but not both, the clearing price for operating reserves is naturally mirrored in and consistent with, the energy settlement price; as the marginal value of reserves increase, so must the marginal value of energy. Through this relationship between reserve and energy pricing, the marginal value of incremental reserves is paid to all capacity dispatched to supply energy in an interval, not just the capacity designated as operating reserve (ERCOT, 2014).

IMPLEMENTATION CHOICES: NO CO-OPTIMIZATION OR LOCAL ORDC

In ERCOT, a decision was made, for simplicity, to implement the ORDC and reserve scarcity pricing without full co-optimization in the dispatch of energy and operating reserves. Instead, the marginal value of reserves is calculated for each dispatch interval, based on the value of the ORDC for the quantity of physically responsive reserve capacity for the interval, and the resulting price is added to each MW of reserves or energy scheduled in a dispatch interval.

An important assumption in the ERCOT ORDC implementation is that all reserves in ERCOT are equally valuable in maintaining reliability. The ORDC price is, by definition, the price of scarcity resulting from the probability of failure to balance load and generation system-wide. The LOLP underlying the ORDC is estimated for the ISO as a whole, as the probability of ERCOT needing to shed load in the real-time dispatch given varying levels of region-wide on-line and off-line reserves. The possibility of operating reserve demand varying locally within ERCOT was discussed at the time ORDC was implemented, but was not pursued.

The ERCOT ORDC produces a number of benefits and represents a leap forward in the design of the scarcity pricing mechanism in ERCOT. Through the economic dispatch, the ORDC determines the scarcity price of reserves and the consistent energy price for all energy. It is consistent with dispatchable demand, and would provide efficient incentives for demand to bid into the dispatch. Furthermore, the ORDC is compatible with offer curve mitigation to deal with any system-wide market power concerns, and clearly distinguishes between cases of high ERCOT-wide prices because of underlying capacity scarcity versus high prices because of an exercise of market power. In principle, the ORDC addresses ERCOT-wide scarcity pricing and the resulting missing money needed to support at least all economic investment in capacity (Hogan, 2013). The ORDC is not designed to support investment that is not economic given the reliability levels implied by the estimated LOLP. However, as discussed at length below, numerous factors external to the ORDC influence its performance as a scarcity pricing mechanism.

Challenges to Energy Price Formation

In ERCOT's energy-only market, suppliers are paid for sales of energy and ancillary services, with additional adder values for scarcity as reserves diminish (ORDC) or reliability actions affect prices (Reliability Deployment Price Adder).[4] Under the energy-only market design these payments are intended to provide compensation for supply to be available – of the right type and in the right location – for reliable system operation.

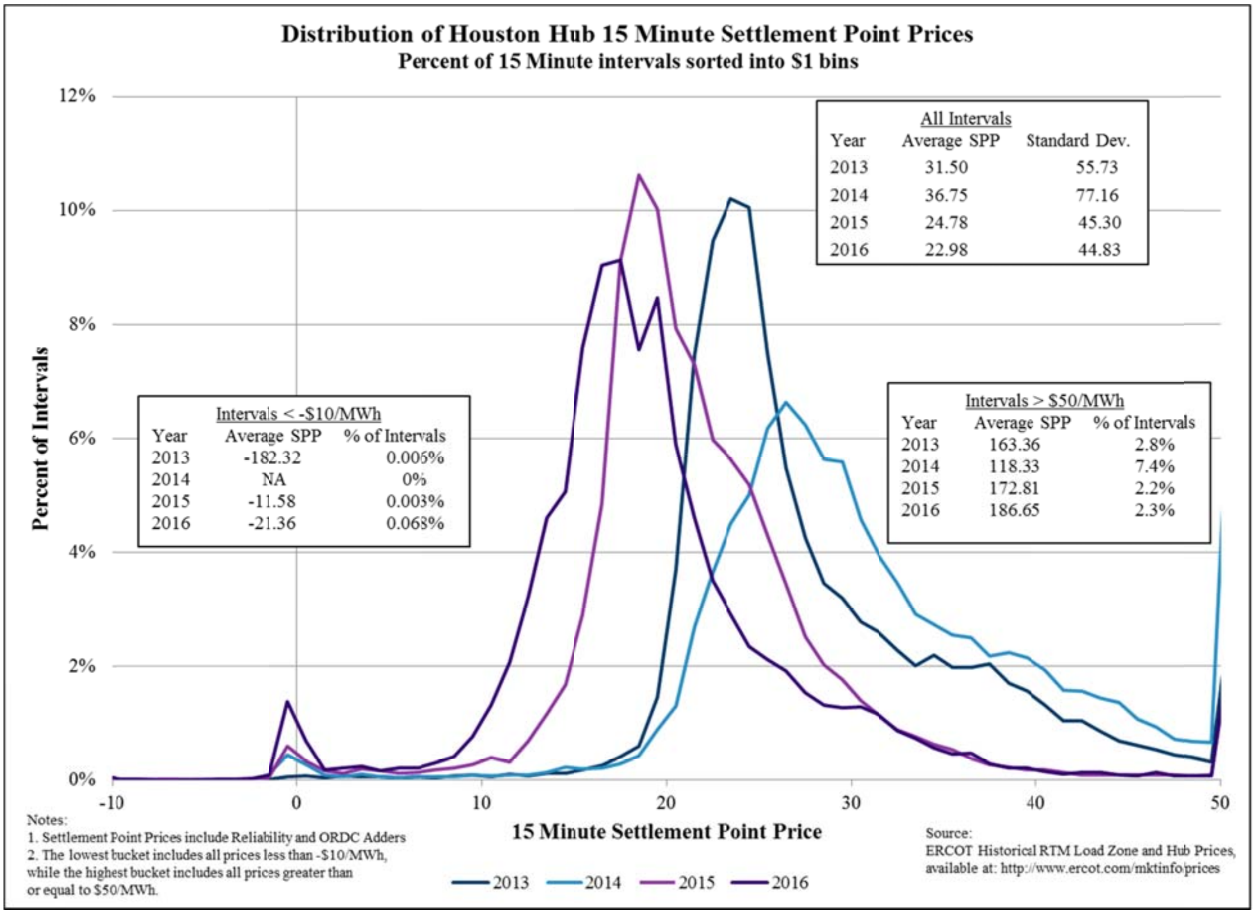
In the ERCOT market, distortions to the energy price are evident and must be addressed by identifying and correcting their origin in energy market operations or price formation. Sustaining the energy-only market design requires that pricing reflect and be consistent with the value of energy and the cost of actions occurring, or that need to occur, to maintain reliability.

The data in Figure 3 show the recent trend in locational prices at the Houston Hub, inclusive of the ORDC adder and the Reliability Deployment Price Adder. There has been a noticeable decline in energy prices since 2014. The downward shift in prices over time is the result of many factors, some of which are structural and are unrelated to the energy-only market design, although they interact with it. Subsidized wind had a meaningful impact for the first time in 2016. In addition, the decline in natural gas prices accounts for a substantial amount of the reduction in energy prices and financial pressure on inframarginal rents for non-renewable, dispatchable producers in Texas. Potomac Economics reported that 2016 natural gas prices in ERCOT were at their lowest level for 15 years, and that the average real-time price in 2016 of $24.65 per MWh was the lowest on record for ERCOT, going back to the start of the zonal market in 2002.[5] These important market conditions have a material impact, but they do not in themselves indicate a problem with the market design assuming pricing outcomes are the direct result of the market conditions. Low prices due to market fundamentals are a sign of effective market operation.

[4] ERCOT NPRR 568, "Real-Time Reserve Price Adder Based on Operating Reserve Demand Curve," approved November 19, 2013, and ERCOT NPRR 626, "Reliability Deployment Price Adder," approved August 12, 2014.

[5] *Megawatt Daily*, "ERCOT sets price, wind records in 2016: IMM," February 15, 2017, p. 4.

Figure 3



Below we examine other factors suppressing or altering energy prices in ERCOT that are not the result of broader economic changes. These effects are separate from market fundamentals and highlight remaining market design challenges. Some issues impacting the energy-only markets are the result of federal or state-level statutes or regulations, such as production or investment tax credits for wind and solar producers. Other issues lie within the jurisdiction of the PUCT and impact the energy-only market, but are not part of the energy-only market design. An example of this is the process for transmission planning and cost allocation. Finally, there is a third class of issues, lying clearly within the domain of the energy-only market design. Several of these center on the relationship between prices and ERCOT actions to maintain reliability, suggesting the need for improved local scarcity pricing, including the possible introduction of local operating reserve requirements. A further feature distorting the critical linkage between prices and the cost to deliver electricity is the omission of marginal losses. Without regard to the origin of the issues, the purpose here is to describe the price formation impact and to consider how it must be addressed as a market design problem with the objective of getting the prices right.

The discussion below of challenges to price formation is organized around three topics:

- **System-wide Price Formation**: The impact of subsidies for renewable resources and other out-of-market influences on ERCOT's region-wide dispatch and prices. This section presents important improvements to address region-wide price formation issues, including adjustments to the system-wide ORDC consistent with the reliability impacts of changes in the generation supply mix and out-of-market commitments, and the addition of the cost of marginal losses to ERCOT's energy market dispatch and pricing consistent with the best practice in all other U.S. ISOs.
- **Local Scarcity Pricing:** The lack of pricing mechanisms to value ERCOT actions to maintain local (as opposed to regional) reliability. A review of local price formation in the event of a reliability unit commitment, particularly in combination with the mitigation of local market power, shows the clear need for market rule changes to ensure that energy prices rise, rather than fall, in regions experiencing local scarcity. This section proposes important changes to ERCOT price formation to value scarcity when out-of-market actions occur to maintain local reliability during conditions of transmission scarcity or when locational operating reserves diminish.
- **Transmission Planning and Cost Recovery:** The effect of ERCOT's policies for transmission investment and cost recovery on price formation. This section motivates an urgent need to consider alternatives to socialized transmission planning and cost recovery to avoid unintended subversion of ERCOT's market-driven model for generation investment and the distortion of energy-only prices through the cost recovery rules for sunk transmission costs.

A technical Appendix provides details on a formulation and computational approach for the calculation of co-optimized prices for energy and operating reserves with local reserve requirements.

System-wide Price Formation Issues

Policies outside the scope of the basic electricity market design have a significant impact on the results of efficient markets operating under these policy umbrellas. A first grouping of policies includes those that subsidize renewable resources, energy efficiency and demand response with funding from sources outside of the energy-only market. As a result, the size and extent of the investments in the targeted assets or programs is not consistent with what a risk-taking investor would willingly invest if the only return were energy market revenues. This has had a major effect on the prices in the ERCOT, increasing the need for reforms to sustain a market design in which energy prices and risk taking by private investors drive investment in electricity assets.

This section discusses the impact of these subsidies on the energy-only market and describes the following changes to better align energy-only prices with the least cost dispatch in support of reliability.

- **Marginal Losses Pricing:** Add the marginal cost of losses to ERCOT's energy market dispatch and pricing.
- **Enhancements to ORDC:** Improve the ORDC calculation to address the reliability impacts of changes in the generation supply mix and the price impacts of reliability deployments.

RENEWABLE RESOURCES RECEIVE OUT-OF-MARKET COMPENSATION

The ITC and PTC have spurred a large increase in renewable investments in ERCOT and have been a major factor in changes to the balance sheets of dispatchable electricity generation owners in the region. These changes cannot be reversed. But an examination of the impact of these policies external to the market reveals areas for improvement to region-wide price formation in ERCOT to support greater efficiency and sustainable electricity markets.

Production Tax Credit and Investment Tax Credit Incentives

Renewable resources receive payments from a variety of state and federal level programs that are in addition to their earnings from market-based sales of power.[6] The most important of these out-of-market payments is the Federal Renewable Electricity Production Tax Credit (PTC), which in December 2015 was extended through December 31, 2019.[7] The PTC is $0.015 per-kWh in 1993 dollars, adjusted for inflation, resulting in a 2016 tax rebate of $0.023/kWh for wind, geothermal, and closed-loop biomass generation. The tax credit applies to a facility's first

[6] Many federal policies and subsidies affect energy market and supply and demand, in addition to those discussed herein.

[7] Energy.gov. "Renewable Electricity Production Tax Credit (PTC)," available at: https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

ten years of operation, and more recent facilities are subject to a reduction in the PTC depending on the year of construction. Some facilities have the option to make an irrevocable election to claim the Business Energy Investment Tax Credit (ITC) instead of claiming the PTC, allowing a deduction of up to 30% of the cost of renewable energy technology on federal income taxes, although the percentage varies by technology and year.[8]

Texas also has several state-level programs to encourage the development of renewable generation, but their impact is dwarfed by the incentives of the Federal PTC and ITC. Texas programs include a renewable generation requirement (renewable portfolio standard)[9,10] and a renewable energy credit (REC) program administered by ERCOT[11] to support renewable portfolio standards applied to retail energy providers.[12] The REC prices in ERCOT have been the lowest in the country since the beginning of 2013 due to the substantial build out of wind resources, at less than $1 per MWh.[13] Additionally, there is a Solar Energy Business Franchise Tax Exemption, which is either .375% or .75% of the taxable entity's margin,[14] and is available to businesses selling and installing wind and a variety of solar technologies, and also to the businesses buying the equipment.[15]

Figure 4 below shows the capacity of wind additions in ERCOT by year, in response in part to the strong financial incentives of the PTC and ITC.

[8] Database of State Incentives for Renewables and Efficiency. "Business Investment Tax Credit," available at: http://programs.dsireusa.org/system/program/detail/658.

[9] National Conference of State Legislatures. "State Renewable Portfolio Standards and Goals" http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

[10] Intermediate goals, according to PUCT Substantive Rule §25.173 were: 2,280 MW by January 1, 2007, 3,272 MW by 2009, 4,264 MW by 2011, and 5,256 MW by 2013.

[11] ERCOT "Renewable Energy Credit," available at: http://www.ercot.com/services/programs/rec

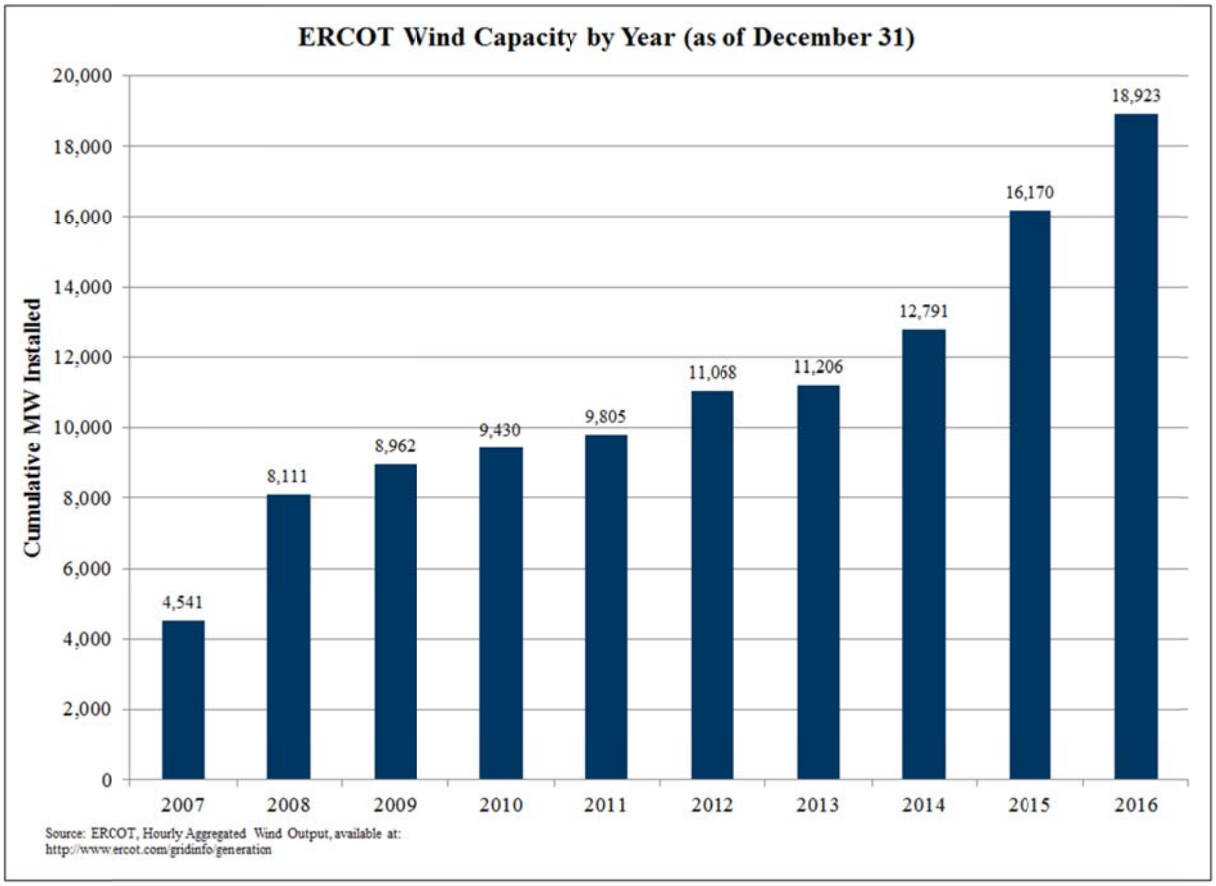
[12] PUCT Substantive Rule §25.173, available at: https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.173/25.173.pdf.

[13] US Department of Energy: Energy Efficiency and Renewable Energy. "Renewable Energy Certificates," available at: http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5.

[14] Texas Comptroller, "Franchise Tax," available at: https://www.comptroller.texas.gov/taxes/franchise/.

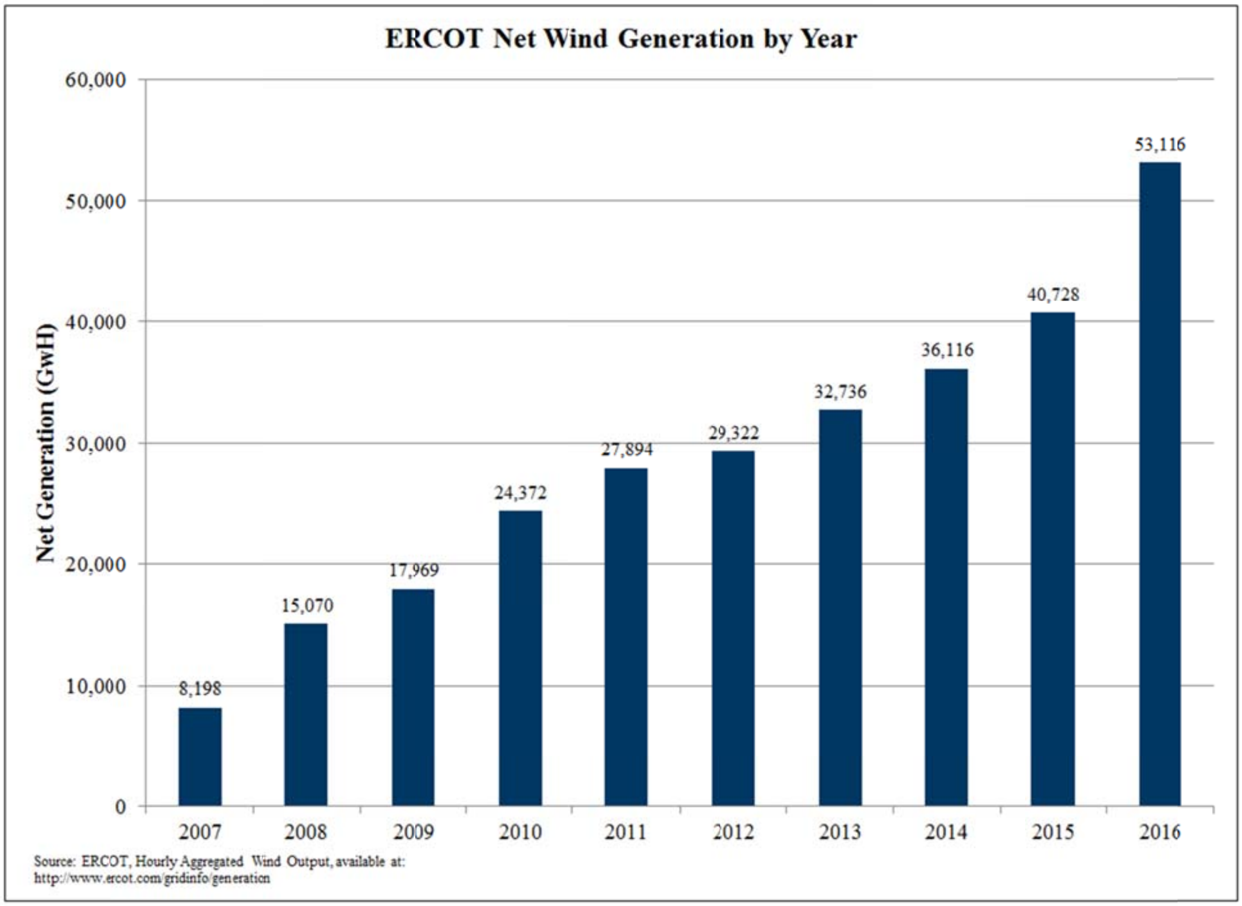
[15] Texas Tax Code Chapter 11.27.

Figure 4



Actual wind output has similarly increased over time, without a significant reduction in capacity factor as new developments have come on line. Total wind production in 2011 was 27,894 GWh in comparison with an output of 53,116 GWh in 2016, as seen in Figure 5:

Figure 5



Efficiency Impact of PTC on ERCOT Dispatch and Prices

When a PTC is paid, the payment is triggered by actual production, in effect changing the marginal cost intended to incent suppliers to produce electricity. The current PTC for qualifying renewable systems is $23 per MWh, meaning that a qualifying supplier would want to produce as much as possible whenever the locational price at its location was greater than -$23 per MWh, because at any price just above -$23 per MWh, its total payment, including the PTC, would be positive.[16] In effect, from the perspective of the generator, the marginal cost for wind has been reduced from approximately zero to -$23 per MWh. Of the approximately 18,923 MW of wind capacity in Texas in 2016, approximately 2,704 MW elected a cash grant or ITC under the American Recovery and Reinvestment Act of 2009, leading to an estimate of over 16,000 MW of wind operating in ERCOT with a production tax credit. Approximately 16,000 MW of

[16] Energy.gov. "Renewable Electricity Production Tax Credit (PTC)," available at: https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

wind capacity in Texas thus has an incentive to operate as much as possible, even at locational prices less than zero.[17]

The PTC modifies the actual marginal cost, which affects the wind generator's offer, which then alters the locational price signal and may lead to a higher-cost dispatch than would have occurred without the tax credit. For example, this would be evident when the renewable supplier is injecting power into the system that has a negative locational price. A locational price of -$2 per MWh, for example, means that in order to accommodate the injections of power from the renewable supplier without compromising reliability, the dispatch of other suppliers and loads on the system had to be adjusted and the net cost (*not* savings) of these other adjustments on the margin was $2 per MWh, equivalent to subsidizing incremental load.[18]

Along with the economic dispatch, locational prices are altered by the PTC. Figure 6 shows the number of intervals of the year, from 2013-2016, in which there were negative prices at four ERCOT trading hubs. Prior to the increase in wind and other intermittent capacity in the ISOs, negative prices sometimes occurred in the middle of the night, as load dropped and generators needed for operation the following day were pinned at their minimum loads. In contrast, the increasing incidence of negative prices in ERCOT is caused by the incentive of the owners of wind generation capacity receiving the PTC to continue to produce even when the locational price is negative.

The relatively high frequency of negative prices observed in the western part of ERCOT occurred because the large number of wind farms in the rural western and northern areas of the state overwhelmed export capacity of the local transmission system and created transmission constraints that can limit the export of this power to other regions of ERCOT.[19] As the Competitive Renewable Energy Zones (CREZ) transmission project reached completion and installed capacity of wind generation continued to grow, system dispatch at negative prices increasingly impacted prices at the Houston, Southern, and Northern Hubs, as power from wind is setting the prices more frequently outside the West zone, as seen in Figures 6 and 7.

[17] "1603 Program: Payments for Specified Energy Property in Lieu of Tax Credits," available at https://www.treasury.gov/initiatives/recovery/Pages/1603.aspx

[18] Viewing the PTC as an imperfect estimate of the social cost of carbon emissions (and other emissions) avoided by the use of renewable energy rather than fossil-fuel fired energy is a relevant element to evaluation of the effect of the production tax credit on social welfare. This paper does not attempt to unwind the diverse and complicated efficiency impacts of state and federal government programs to increase electricity production from renewable sources. Programs to encourage electricity production from renewable sources may move in the direction of efficiency, but a policy that does not apply consistent subsidies or charges to all carbon-emitting sources within a broad region could have complex second-order welfare effects.

[19] EIA, "Today in Energy," June 24, 2014, available at: http://www.eia.gov/todayinenergy/detail.php?id=16831.

Figure 6

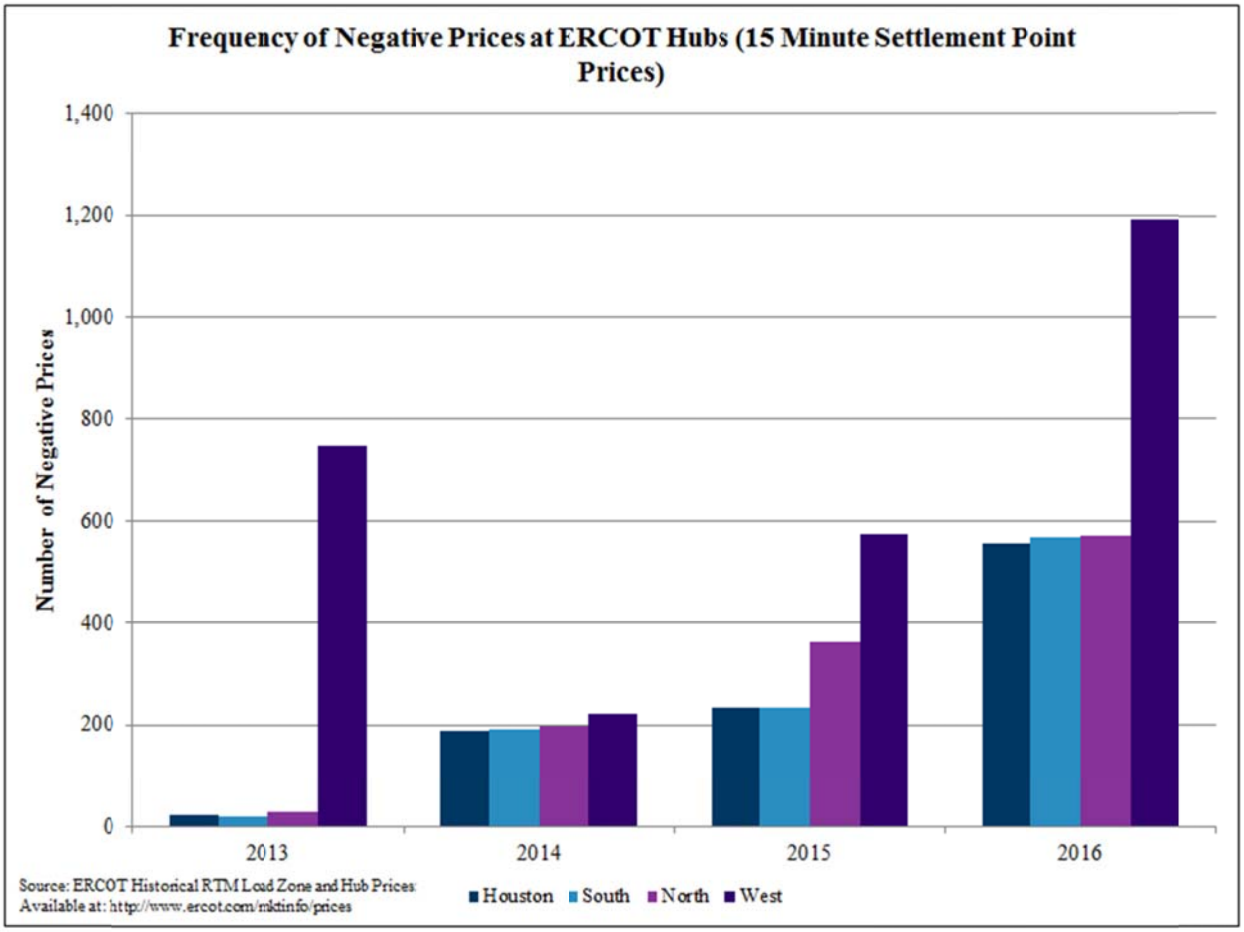
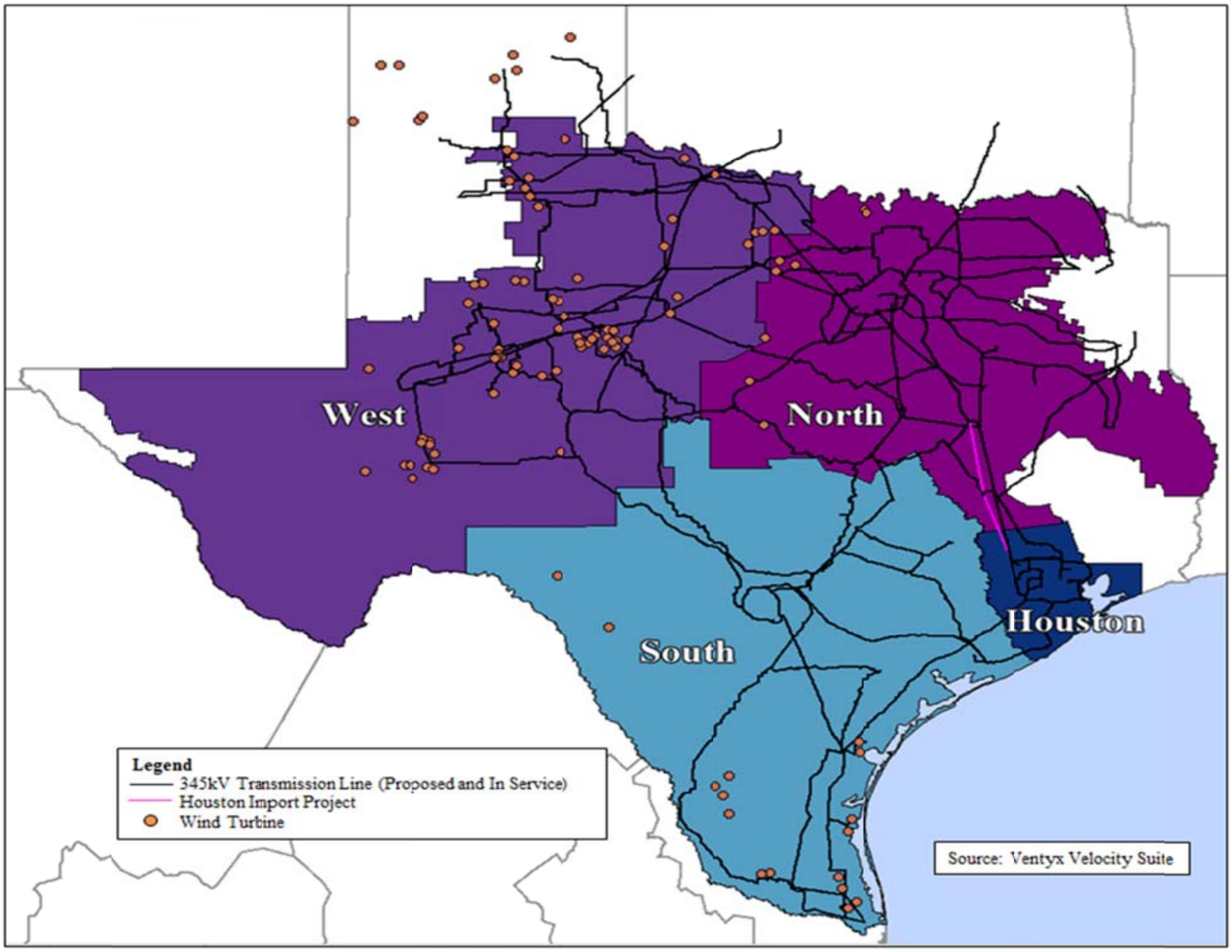

Frequency of Negative Prices at ERCOT Hubs (15 Minute Settlement Point Prices)
Number of Negative Prices
1,400
1,200
1,000
800
600
400
200
0
2013
2014
2015
2016
Source: ERCOT Historical RTM Load Zone and Hub Prices
Available at: http://www.ercot.com/mktinfo/prices
Houston
South
North
West

Figure 7
ERCOT Wind Turbines and 345 kV Transmission Lines



Subsidized wind energy is not only increasing the frequency of negative prices in ERCOT, it is decreasing prices in every hour that the wind farms are generating. The degree of effect of subsidized wind production on locational prices depends on the relationship between the amount of wind and the unit commitment, which determines the shape of the electricity supply curve during each interval. If there were a number of units operating near minimum load, the supply curve could be relatively flat over a range of output near the market clearing, so that variations in the quantity of wind might shift the supply curve but would have a relatively small impact on price. With higher levels of load, the supply curve would likely start to slope upwards more sharply, as units with higher heat rates would be needed to meet demand, so an increase in wind during a high load interval would likely lead to a larger drop in price. Locational prices result from the interplay between forecasts of the level of wind output, commitment decisions, and the actual wind conditions during a 5- minute interval.

Figures 8 and 9 on the following two pages are based on actual ERCOT data for 1 AM on August 1, 2016 and April 4, 2016.[20] These show the impact of varying levels of wind production on prices in ERCOT in an unconstrained dispatch to serve 45,000 MW of load on August 1, and 25,000 MW of load on April 4.[21]

As the quantity of wind supply changes from 0 MWh, to 5,000 MWh, to 10,000 MWh, to 15,000 MWh, it shifts the supply curve to the right in successive panels of the figures, reducing the clearing price for any level of electricity demand. In the August 1st illustration, with a load of 45,000 MW, the clearing price starts at $30.02 per MWh with no wind, falling to $26.25 per MWh with 5,000 MWh of wind and then to $22.82 per MWh with 15,000 MWh of wind.

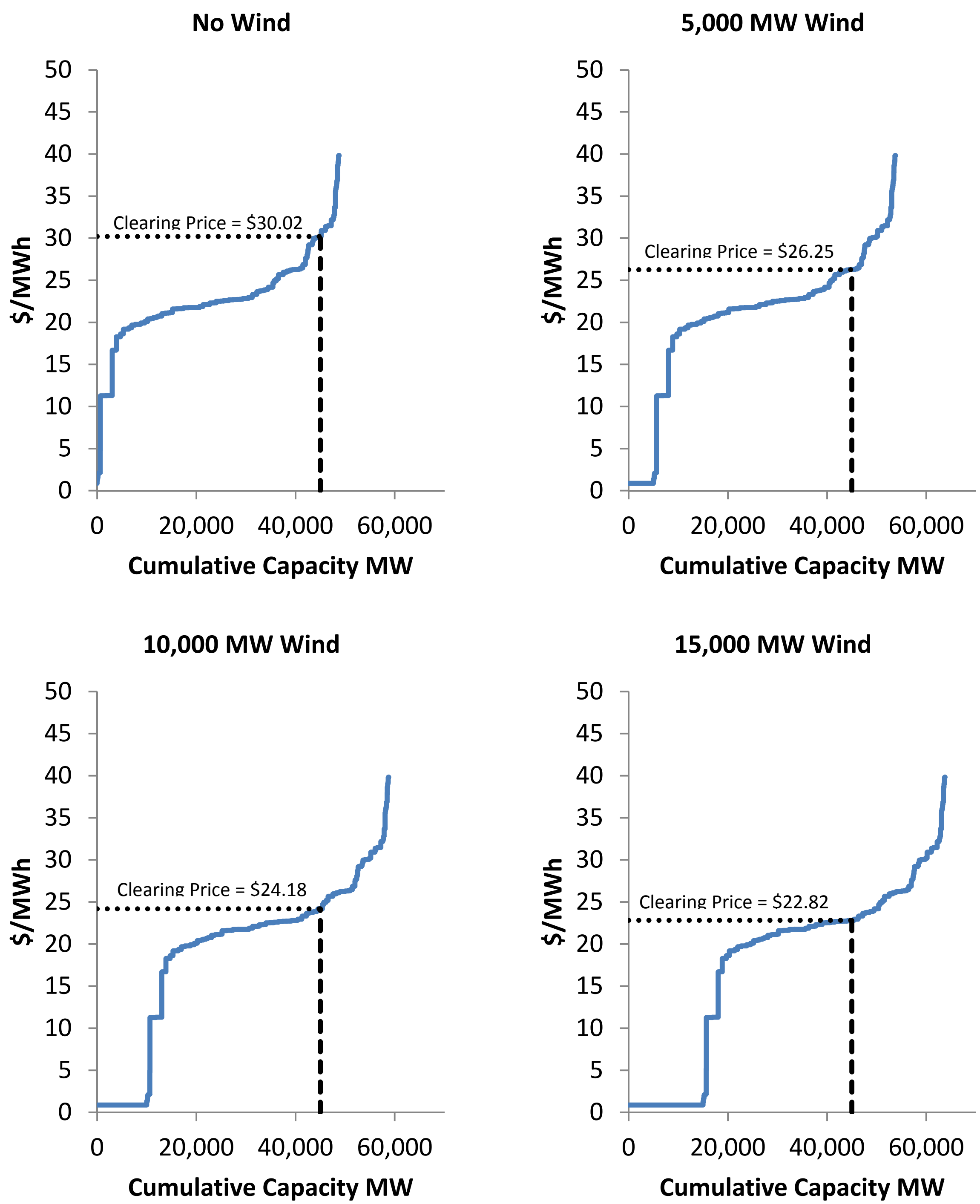
The example for April 1st illustrates how the impact of the wind power on prices depends on the capacity online in an interval. In the April 4th illustration, the clearing price falls $2.67 per MWh when the first 5,000 MW of wind power enters the grid but then falls less, by $1.42, when wind increases another 5,000 MWh to 10,000 MWh.

It is possible that price increases may not be as large as shown in the figures if wind were to drop because, for instance, ERCOT might be able to quickly arrange for increased imports or bring additional capacity on line. Similarly, there could be much larger price changes than shown here in some intervals from a drop in wind if there were insufficient capacity available to ramp. But the illustrations clearly suggest how over many hours the accumulation of the price impact on dispatchable generation not receiving the PTC sums to a very substantial reduction in its net margin.

[20] The impact of subsidized wind production on prices has been estimated with the simplifying assumption of no active transmission constraints.

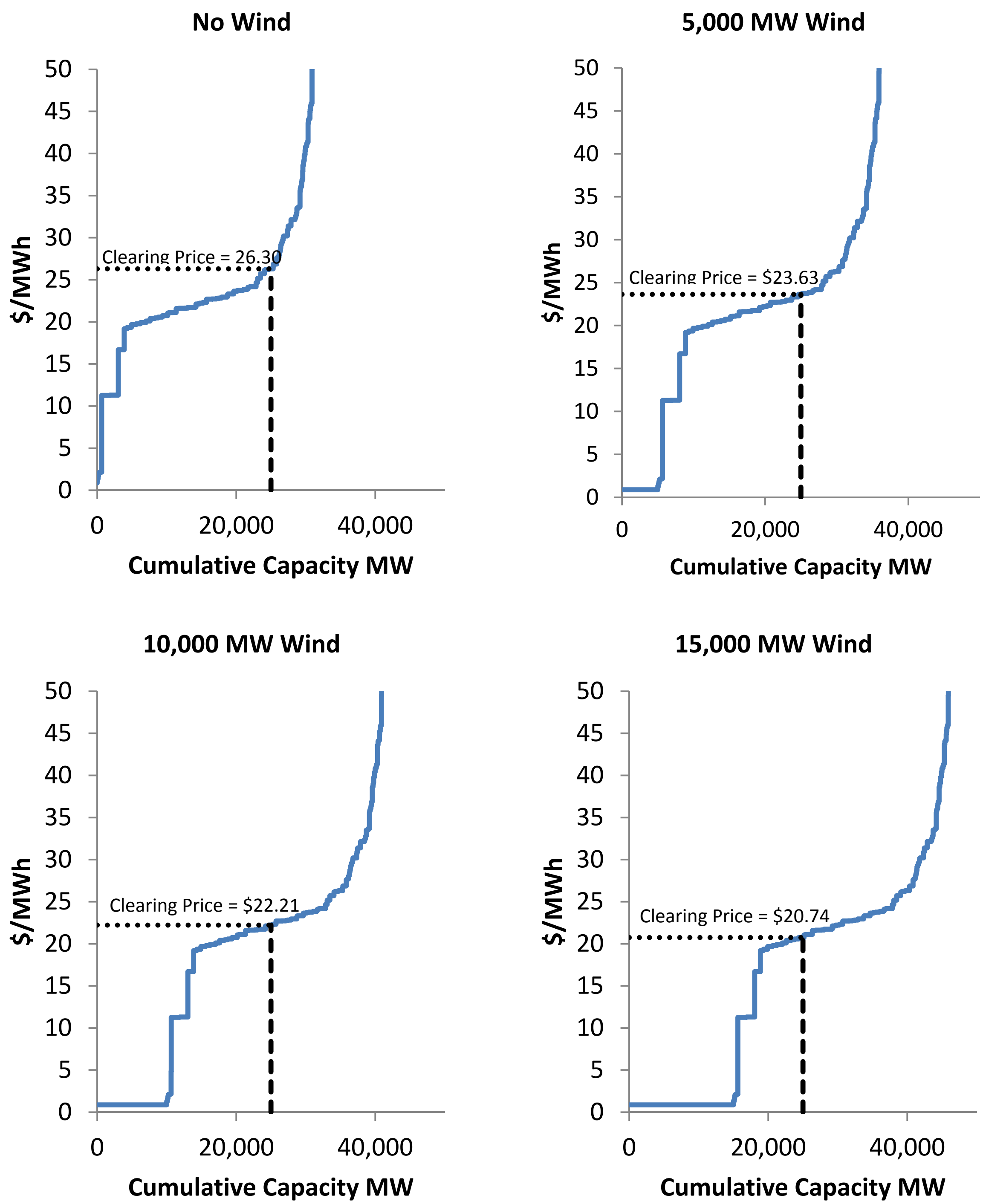
[21] The bid of $0 per MWh for wind supply is used for purposes of illustration.

Figure 8
Illustrative Off-Peak ERCOT Supply Curve
1 AM August 1, 2016 (45,000 MW Load)



Cost and capacity data from Ventyx Supply Curve Analyst for August 4, 2016. Removed units not in operation. Using Ventyx data set for plant level generation on August 1 2016 at 1 AM, additional units removed if they had no net generation and were larger than 50 MW.

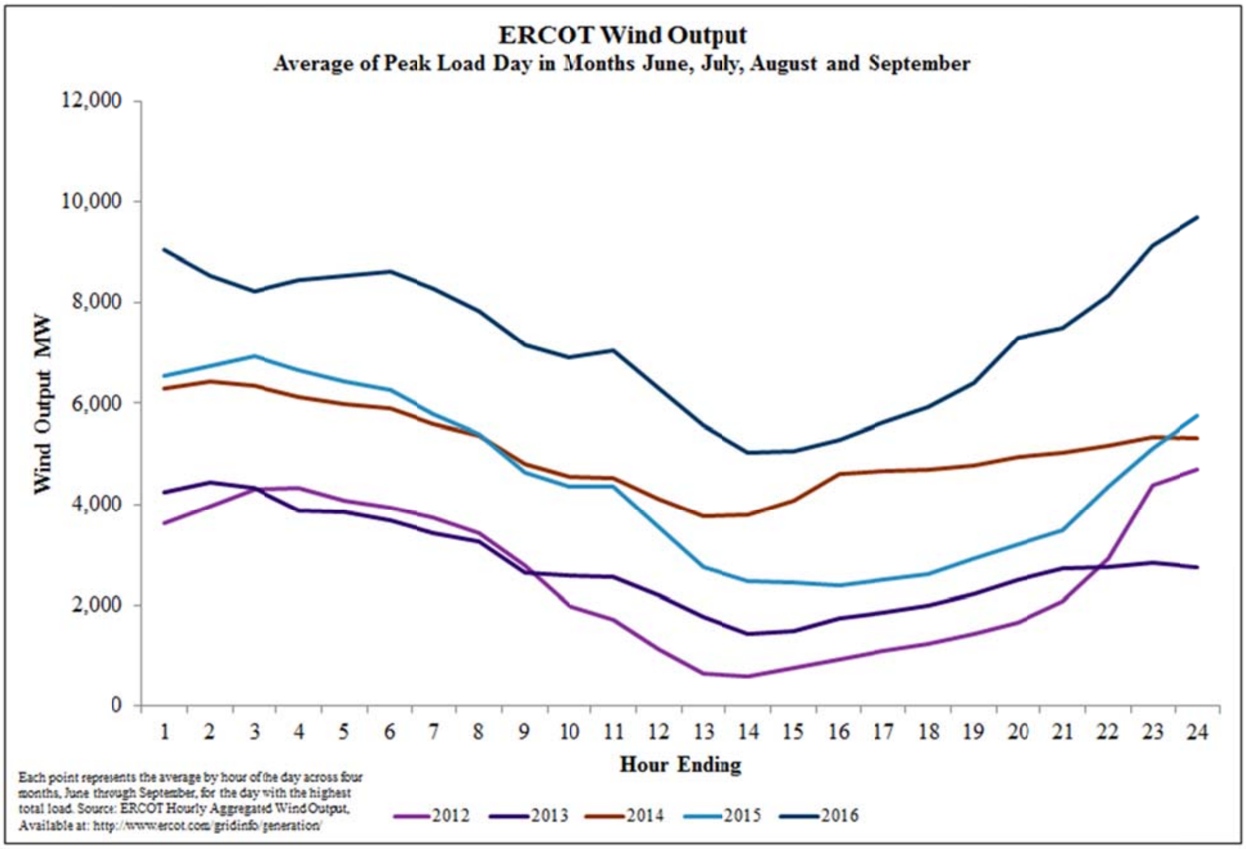
Figure 9
Illustrative Off-Peak ERCOT Supply Curve
1 AM April 4, 2016 (25,000 MW Load)



Cost and capacity data from Ventyx Supply Curve Analyst for April 1, 2016. Using Ventyx data set for plant level generation on April 4, 2016 at 1 AM, additional units removed if they had no net generation and were larger than 50 MW.

The increase in the quantity of wind production in ERCOT has occurred in both on-peak and off-peak hours, as the diurnal characteristics of new wind developments along the Gulf Coast differ from those of earlier wind developments in the western area of ERCOT. Figure 10 below, for example, shows that the quantity of wind output in ERCOT in the middle of the day in the four peak days of the year rose from less than 1,000 MW in 2012, to well over 5,000 MW in 2016. Although wind is intermittent, it is clearly decreasing the probability of scarcity and an ORDC adder during peak hours.

Figure 10



The PTC affects the level of dispatch of non-wind suppliers as well as their locational prices. In hours in which a non-wind supplier would have been infra-marginal in the absence of PTC, it may now not be running, or may be running at a lower dispatch point. This decreases its energy margin, which in an energy-only market is the primary source of revenue to pay for supplier fixed costs.

It is important to note that the ITC does not have the same impact on marginal incentives and locational prices as the PTC. The ITC affects incentives to build new renewable capacity and increases the quantity of intermittent capacity bidding at low prices into the ERCOT electricity market, but once the capacity is built, suppliers receiving the ITC will respond efficiently to locational prices and, in particular, will not have an incentive to supply at negative prices.

Impact of Increasing Intermittent Generation on Ancillary Service Needs

Secondary to the impact on energy prices, the increasing reliance on intermittent resources, such as wind, also potentially affects ERCOT's requirements for ancillary services. In ISO capacity markets outside ERCOT, non-intermittent suppliers are compensated more highly for nameplate capacity than intermittent suppliers because of the dependability of their supply. A capacity market payment, in principle, is the market-clearing payment required by the marginal capacity supplier, in addition to its energy and ancillary services market revenue, in order to impel it to be available. The capacity market payment compensates for the missing money in expected energy and ancillary service market payments in order to ensure that sufficient capacity is in operation to meet reliability standards. In ERCOT's energy-only market, though, the price signal that rewards the short- or long-run value of non-intermittent, dispatchable supply is a combination of the energy price, the ORDC adder paid during ERCOT-wide scarcity, and the Reliability Deployment Price Adder.

For several years, ISOs experiencing increases in intermittent generation have been studying the possible need for new requirements for regulation, inertial response and operating reserves. The same questions about ancillary services are arising in ERCOT, and the possibility of increased system efficiency led to an investigation of the benefits of alternative ancillary service product definitions and requirements, such as synchronous inertia service.[22] During 2016 in ERCOT, the largest 1 hour upward ramp was 3,624 MW, and there were 49 hours over the year with hourly upward ramps of over 2,000 MW. The largest downward ramp was 3,080 MW, and there were 38 hours with downward ramping of over 2,000 MW.[23] Despite this variability in supply, ERCOT's ability to manage system frequency has improved, which eliminated the need to modify ancillary services at this time.[24] The question remains whether changes in the size of hourly ramps, and other changes related to the increase in intermittent generation, necessitate, or would lead to benefits from, new or revised reliability constraints and requirements within ERCOT's energy-only market design.

[22] ERCOT. "NPRR 667 Ancillary Service redesign 111814," November 8, 2014, available at: http://www.ercot.com/content/mktrules/issues/nprr/651-675/667/keydocs/667NPRR-01_Ancillary_Service_Redesign_111814.doc.

[23] ERCOT 2016 Hourly Aggregated Wind Output, available at: http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13424&reportTitle=Hourly%20Aggregated%20Wind%20Output&showHTMLView=&mimicKey.

[24] ERCOT "Monthly Operational Overview," March 15, 2017, p. 6, available at: http://www.ercot.com/content/wcm/key_documents_lists/27311/ERCOT_Monthly_Operational_Overview_201702.pdf

The California Independent System Operator (CAISO) and the Midcontinent Independent System Operator (MISO) worked for several years to develop ramping products to compensate flexible dispatchable generators for the ability to increase or decrease their output quickly. These efforts illustrate the connection between evolving capabilities for how and when ancillary services are scheduled in an ISO's real-time unit commitment and dispatch software, the determination of whether or not a ramping product or other change to ancillary service requirements is needed, and the effectiveness of any proposed implementation approach. The CAISO implemented a flexible ramping constraint in its short-term unit commitment process (real time pre-dispatch, RTPD) in December 2011 and the MISO has been committing capacity to provide "headroom" even longer. These early processes, however, did not insure that the desired ramping capacity was maintained in the dispatch. In particular, the CAISO process tended to create phantom ramp, because of the assumption that capacity available to ramp hour ahead would actually be available to ramp in real time. Their implementation of the hour-ahead ramping constraint did not entail paying units the opportunity cost of capacity reserved to ramp rather than being dispatched for energy in real-time.

In May 2016 the MISO implemented a ramp capability dispatch and in December 2016 the CAISO implemented a similar dispatch design referred to as the flexible ramping product.[25] Because the CAISO clears both a 15-minute and a 5-minute real-time market, the CAISO ramp pricing design provides compensation both to resources dispatchable in a 5-minute time frame and a 15-minute time frame; the market-clearing price is calculated based on both opportunity costs and penalty factors.[26] The MISO product is implemented within a single-interval real-time dispatch for energy and reserves. The CAISO does not co-optimize energy with other ancillary services in its 5-minute multi-interval dispatch, although this is under consideration. Ramping is considered in the look-ahead commitment in both ISOs.

A key consideration in the implementation of a dynamic product, such as ramping, is the connection between the scheduling and pricing of the product and any inter-temporal optimization of the dispatch. For example, under the idealized conditions of an energy-only market, co-optimization in a dynamic framework will produce LMPs that reflect ramping constraints and compensate the provision of the corresponding ramp without requiring the definition of new products. Although ERCOT and its stakeholders have been examining the

[25] MISO Market Subcommittee. "Ramp Capability Product Performance Update," November 29, 2016, p. 2, available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2016/20161129/20161129%20MSC%20Item%2005f%20Ramp%20Capability%20Post%20Implementation%20Analysis.pdf; FERC. "Order on Tariff Revisions," September 26 2016. Docket No. ER16-2023-000.

[26] Bushnell, Harvey and Hobbs, "Opinion on Flexible Ramping Product," CAISO Market Surveillance Committee, DRAFT, January 20, 2016, available at: https://www.caiso.com/Documents/Draft_MSC_Opinion_FlexibleRampingProduct-Jan2016.pdf.

need for a "Multi-Interval Real Time Market," this possible innovation is not a current priority. A discussion of the need to develop new dynamic products or services would be most productive as a component of a broader discussion of the costs and benefits of explicit real-time inter-temporal co-optimization of energy and ancillary services as a refinement in getting the prices right when changes in net load could occur that have not been forecasted.

UTILITY ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS REDUCE PEAK LOAD

Energy Efficiency (EE) and Demand Response (DR) programs in Texas continue to grow and reduce projected ERCOT peak electricity demand. Beginning January 1, 2013, the Texas PUCT implemented a Texas 2011 legislative directive requiring utility EE/DR program goals to be measured as a percentage of peak demand, as opposed to prior measurement as a percentage of projected peak demand growth, increasing the expected impact of these utility programs.[27] Under subsequently adopted PUCT procedures in response to the 2011 legislation, Texas utilities are responsible for administering incentive programs necessary to meet the EE/DR reduction goals.[28] The utility programs are implemented mainly through energy efficiency service providers in order to reduce peak electricity demands and energy consumption.[29] The costs of the EE/DR programs are recovered from utility ratepayers through specific EE/DR cost-recovery charges.[30]

EE/DR programs have progressively reduced peak demand in ERCOT.[31] ERCOT now reports an expected peak demand reduction associated with utility EE/DR programs of 407 MW in 2017, with the reduction expected to grow to 677 MW in 2019.[32]

EE/DR peak demand reductions put additional downward pressure on ERCOT peak period electricity prices. While the change in the supply and demand balance in ERCOT from the EE/DR

[27] Texas Senate Bill 1125, 2011.

[28] See, generally, PUCT Substantive Rule 25.181, "Substantive Rules Applicable to Electric Service Providers, Subchapter H., Electrical Planning, Division 2, Energy Efficiency and Customer-Owned Resources," Energy Efficiency Goal, available at: http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.181/25.181.pdf.

[29] See, generally, Texas Energy Efficiency, available at: http://www.texasefficiency.com/index.php/about/energy-efficiency-rule.

[30] PUCT Chapter 25, §25.181, at C (13).

[31] Frontier Associates LLC, "Energy Efficiency Accomplishments of Texas Investor-Owned Utilities, Calendar Year 2015,", available at: http://www.texasefficiency.com/images/documents/Publications/Reports/EnergyEfficiencyAccomplishments/EEPR2015.pdf.

[32] ERCOT, "Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2017-2026," December 15, 2016, p. 99, available at: http://www.ercot.com/content/wcm/lists/96607/CapacityDemandandReserveReport-Dec2016.pdf, reporting estimated reductions based on 2011 legislation (see page 6). ERCOT's reported demand reductions are based on newly estimated EE/DR peak demand reductions (thus do not include previously achieved reduction) and do not include impacts that may occur after 2019.

programs is not as dramatic as that occurring due to subsidized wind production or the 4CP transmission cost allocation discussed below, the EE/DR programs are a further instance in which out-of-market payments are reducing energy-only prices. EE and DR reductions in peak demand are funded by programs recovered through utility rates, rather than by customer savings achieved from efficient market behavior to reduce consumption that would otherwise be charged the energy-only price plus, possibly, a scarcity adder. These programs reflect state-level policy goals and choices. But there is no avoiding that the existence of these programs has an impact on energy-only market prices in ERCOT, and on the ability of the energy-only market design to operate as intended to incentivize efficient supply and demand reduction.[33]

IMPROVEMENTS TO SYSTEM-WIDE PRICE FORMATION

Retirement of existing facilities, even early retirement, could be consistent with efficient market operations. In ERCOT, the pressure is on dispatchable generation capacity due to falling natural gas prices, increasing wind production spurred by out-of-market payments, and other factors external to the energy market under the direct control of the PUCT. The low level of region-wide energy prices and ORDC adders are sending a message for dispatchable resources to exit the market, and there is a need to evaluate the consequences of increasing reliance on intermittent sources of energy. In particular, these external factors and shifting market conditions highlight the importance of improving price formation to ensure that it is fundamentals, and not avoidable market influences or defects that drive decisions about retirement, entry or plant maintenance. The PUCT and ERCOT have started this process through the review of whether reforms are needed in system-wide pricing, specifically the ORDC.

ORDC Reforms

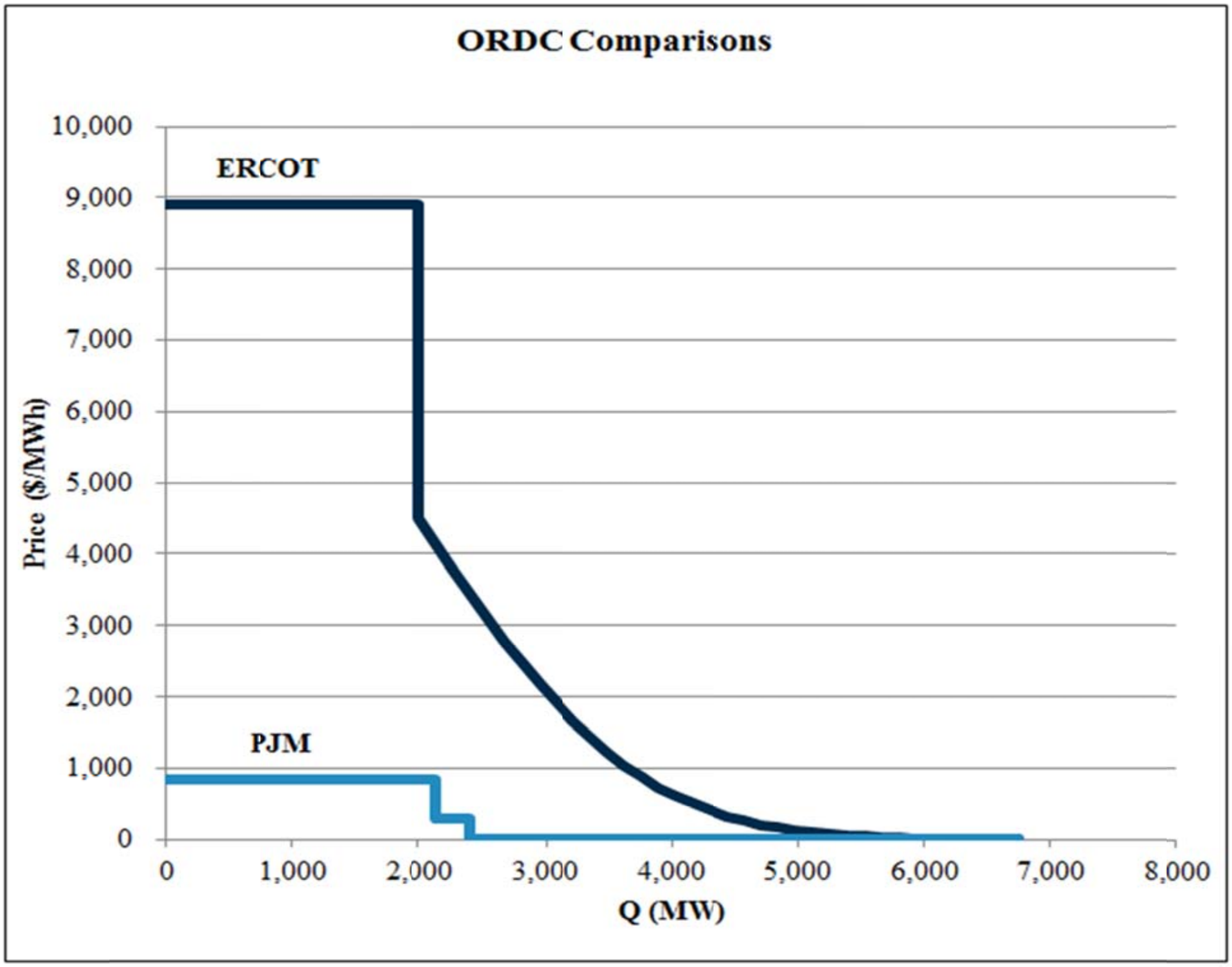
There is a broad range of proposals for changes in the design of the system-wide ORDC (Bryant, Harvey, & Haas, 2016). The discussion has covered many different issues, ranging from a view that implementation of the ORDC has worked largely as expected and there is no need for immediate reforms, to specific suggestions for changing the parameters or utilization of the ORDC.

A focus on evaluation and possible reforms is appropriate, but it is also important to recognize how far ERCOT has come in supporting the use of the ORDC. Although the basic principle of having a demand curve for operating reserves is widely accepted across other organized markets in the United States, it is only in ERCOT that the approach has been explicitly connected to underlying principles of reliability and efficient market design. For example,

[33] The Reliability Deployment Price Adder addresses the price impact of load resource deployment by the IESO, but not load reductions due to distribution level funding of EE/DR.

Figure 11 compares the ORDC implemented in ERCOT with that in PJM, which is a much larger system than ERCOT. In essence, the PJM ORDC is based not on the value of operating reserves but on an estimate of the supply costs of likely providers.[34]

Figure 11



The ERCOT ORDC reflects the value of the reserves, not the cost of supply. In addition, the PJM ORDC does not apply in all hours, but only during declared emergencies.[35] Hence, the PJM ORDC plays a smaller role in the system and PJM has implemented a centrally-organized forward capacity market.

[34] "[T]he $300/MWh price is appropriate for reserves on the second step of the proposed ORDC based on an internal analysis of offer data for resources that are likely to be called on to provide reserves in the Operating Day" (PJM, "Proposed Tariff Revisions of PJM Interconnection, L.L.C.", FERC Docket No. ER15-643-000, December 17, 2014).

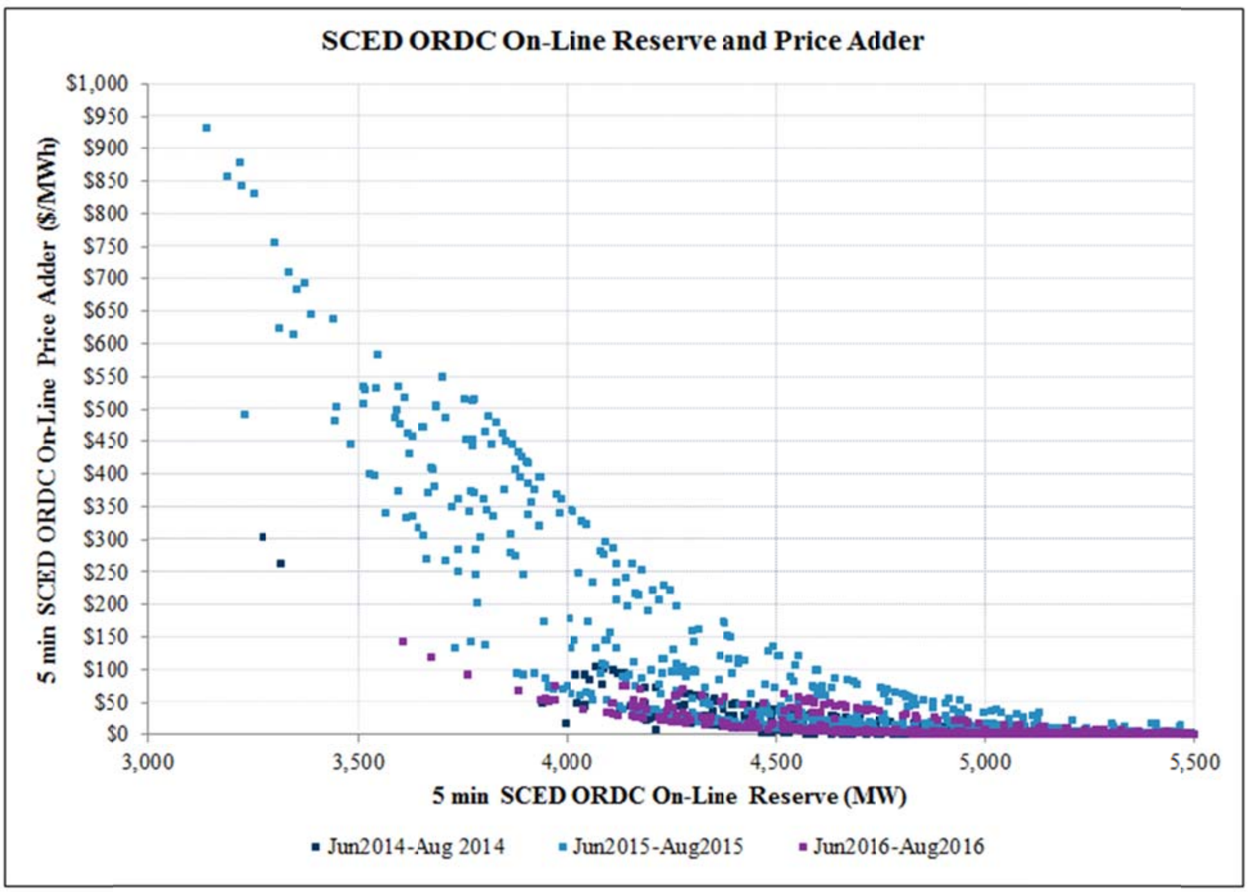
[35] "The ORDCs PJM currently utilizes were designed under the assumption that shortage pricing would only occur during emergency operating conditions and therefore the curves are a step function" (PJM and SPP, "Joint Comments Of PJM Interconnection, L.L.C And Southwest Power Pool, Inc. Addressing Shortage Pricing," FERC Docket No. RM15-24-000, November 30, 2015.).

Opportunities for further refinement of the ORDC fall into four broad categories. There are three parameters that define the shape and magnitude of the ORDC: the "X" factor that sets the level when the price matches the VOLL; the VOLL; and the estimate of the LOLP. A fourth factor is the specific protocols for determining the real-time amounts of the various reserves available that define the scarcity price dictated by the ORDC, such as the accounting for Reliability Unit Commitment (RUC) decisions (Supply Analysis Working Group, 2016).

X Factor

The many proposed changes in the "X" factor focus on the connection with actions the system operator can or should take under stressed conditions. For example, the different stages under the Energy Emergency Alert protocols range from calls for voluntary conservation to mandatory requirements for rolling blackouts. The rolling blackout condition is the idealized case where the price of energy should be set at the VOLL, but the other cases would imply some other scarcity price less than the VOLL.

Figure 12



It would be possible, and was considered in the initial design, to model each of the incremental operator-initiated reliability steps ERCOT could take under emergency conditions. This would produce an ORDC with multiple steps, some probably below and some possibly above the current "X" value of 2,000 MW. This might be appropriate to provide better signals during conditions when actual reserves fall at or below 2,000 MW. However, it is not clear that these proposals would have much impact on the level of the implied scarcity price when operating reserves are well above 2,000 MW. Most of the operating hours, as shown in Figure 12, and most of the experience with scarcity pricing, have been in this higher range of reserves.[36] Hence, the main impact on average revenues may not be much affected by refinements to the "X" value, as the scarcity prices at these higher levels of reserves are driven in large part by the LOLP which would not change much with modest changes in the "X" value.

The proposals for changes in the "X" factor emphasize that there is a more complex picture for the underlying actions under stressed conditions than a one-step transition to load shedding. But a further issue with suggestions to increase the X threshold is that the justification to refine the ORDC to include steps to better match actual operator actions would also lead to an implied scarcity price of less than the VOLL for actions at a lower level of stress than actual load shedding.

The design of the ORDC did recognize this interaction effect and, in part, the choice by the Commission to use a single "X" factor at the VOLL was a compromise in the name of simplicity. A comparison of the compromise with the details of actual operations could be revisited, but the logic of an argument to introduce steps to ORDC representing X factors of increasing severity would likely dictate use of values lower than VOLL for emergency actions of less severity than the case of actual rolling blackouts. The details of an illustrative version of a "multiple emergency actions" ORDC curve appear in the Appendix. On the whole, it is possible that refinement of the X value or the approximation of multiple X steps consistent with emergency actions reflecting differing levels of estimated loss of load probability would not result in a material change to the ORDC scarcity price signal in most hours and would therefore introduce unnecessary complexity.

VOLL

Similarly, the choice of the VOLL of $9,000/MWh was made by the Commission as a reasonable approximation of a more complicated underlying reality. There are many different estimates of the VOLL, under different conditions. The decision was to approximate the average value of lost load of those customers who would be included as a group in an involuntary load curtailment by ERCOT. The group would be heterogeneous, and some would have a higher and some a lower VOLL. But the average is the appropriate measure given the current technology for curtailment. By contrast, voluntary reductions can be accommodated through load bidding

36 Surendran, Resmi, "ERCOT: Role and Value of Scarcity Pricing," 2017, EUCI Presentation, April 10, 2017.

or self-initiated demand reductions and do not need to be part of the definition of the ORDC. Hence, the concept of the VOLL is to estimate the best proxy of the cost to load of emergency actions implemented through actual involuntary curtailment protocols.

LOLP

The loss of load probability (LOLP) is the component most straightforward to estimate. Because of its detailed records, ERCOT can use the available data to estimate the standard deviation and mean for "…historic events defined as the difference between the hour-ahead forecasted reserves with the reserves that were available in Real-Time during the Operating Hour" (Supply Analysis Working Group, 2016, p. 8). This is the definition of the LOLP for the ORDC, which can vary across time to reflect different operating conditions such as changing availability of intermittent renewable sources. This estimate can capture the LOLP and the expected value of operating reserves.

An argument for changing the LOLP arises from a perspective to be conservative in the reliability estimates or due to the increased risk of renewable volatility on reserves. The current LOLP is taken from data and is the correct theoretical framework. However, the analysis assumes that the system operator has an accurate forward-looking model of the system and that there will be no operational surprises outside of the range of history. A natural response to adopting a conservative bias, given the relative lack of foresight or experience in operating a system heavily dependent on intermittent resources would be to make a judgmental adjustment in the margin of safety by shifting the LOLP. This would leave untouched the "X" and VOLL levels, but provide a higher estimated scarcity price during the bulk of the hours at levels where the system normally operates. And the conscious shift of the LOLP would provide a good measure of the degree of the conservative assumption. A shift of a small fraction of a standard deviation would seem not very conservative. A shift of the LOLP by a full standard deviation would seem like a large margin of safety.

Stated in terms of the analytical description of the ORDC, a conservative shift of the LOLP would be a fraction of the standard deviation of the cumulative density function (CDF) estimated for system reliability given a level of hour-ahead reserves (R).

$$LOLP(\mu,\sigma,s,R) = 1 - CDF(\mu + s\sigma, \sigma, R)$$

ERCOT calculates the mean (µ) and standard deviation (σ) of the historical CDF, which follows a normal distribution.[37] The conservative measure would be to shift the mean of the CDF

[37] ERCOT. "Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder", January 1, 2017, available at: http://www.ercot.com/content/wcm/key_documents_lists/89286/Methodology_for_Implementing_ORDC_to_Calculate_Real-Time_Reserve_Price_Adder.zip

function by up to one standard deviation using a scaling value between 0 and 1 ($0<s<1$). This shift would flow directly into the estimated LOLP, as the LOLP is equal to 1-CDF.

The arguments for changing any of these three components of the ORDC, drawn within the framework of the basic design, leave room for judgment about the best approximation of the number of steps in the ORDC, or in the VOLL, used to describe the costs of emergency actions at each step, or a proper adjustment of the LOLP. However, there does not appear to be evidence of a fundamental flaw in the choices made in the original design of the ORDC, and the small average ORDC contribution partly reflects the forces influencing electricity supply and demand described throughout this paper.

An underlying issue remains that the recent availability of capacity has been such that the total scarcity revenues have been low. In short, ample capacity exists in ERCOT partly as a result of renewable subsidies and the underlying economics have produced low average scarcity prices including ORDC price adders. The Commission should recognize that this does not arise from a fundamental flaw in the original design of the ORDC. The ORDC is given certain inputs and it should be expected to produce a consistent set of outputs. An issue suppressing scarcity pricing in ERCOT is that some inputs to the ORDC are distorted by external factors. If the Commission chooses to configure the ORDC to consider the effects of these other factors described in this report, then it would seem natural and consistent with the rest of the design to focus on possible shifts of the LOLP to reflect the increased risk of reserve scarcity.

Reserve Estimates and Out-of-Market Commitments

Application of the ORDC depends on decisions about the measurement methodology for available operating reserves and their translation into an appropriate scarcity price. For example, consider the treatment of Reliability Must Run (RMR) and RUC capacity. The stated motivation for employing such units arises from concerns about reliability. The conditions leading to the activation of RMR or RUC units -- generally transmission congestion -- may differ from the conditions giving rise to a general shortage of operating reserves, but all available capacity nevertheless affects the calculation of the price adder under the ORDC methodology.

If an out-of-market unit is committed by ERCOT, it is by construction selected because the natural market choice, as operationalized in ERCOT's commitment and dispatch models, would not have the unit available or online. However, the ORDC was designed based on economic principles to support market decisions and valuations. Including this non-market capacity in the ORDC determination of a market price distorts the underlying logic of scarcity pricing. There are at least two dimensions to the resulting price distortion in the ERCOT market. First, the scarcity price will be underestimated through the ORDC. Second, the incremental costs of the out-of-market capacity employed but seldom dispatched might be greater, even much greater, than the avoided costs of a reliability event, as estimated by ERCOT's VOLL. The second problem reiterates questions that have been voiced in ERCOT about the cost-benefit justification for committing out-of-market capacity. This is a question going beyond the present focus on the issue of the interaction between the commitment of the out-of-market capacity and scarcity price formation under the ORDC. It entails improvement of the unit commitment and dispatch models themselves, rather than just an improvement to pricing, but it should be duly noted.[38]

With regard to the problem of the underestimation of the scarcity price, a natural approach to addressing the reliability capacity that the system operator commits or pays for outside the normal energy-only locational energy prices would be to decrease the operating reserves by the amount of the out-of-market commitments. This would be equivalent to decreasing the Real-Time Online Reserves by the amount of the capacity made available by the out-of-market action including capacity above the low sustainable limit.[39] For purposes of calculating the ORDC scarcity price, this rule change would restore the integrity of the calculation of Real-Time Online Capacity when there is an out-of-market commitment. A similar argument might apply to formal demand response programs where the system operator pays separately for the demand response commitment, or other capacity deployments currently included in the methodology for the Reliability Deployment Price Adder. For all of these out-of-market actions, the same logic used for estimation of the Reliability Deployment Price Adder would suggest decreasing the calculation of Real-Time On-Line Reserve Capacity by the quantity of capacity committed and available to be deployed.

Add Marginal Cost of Losses to Dispatch and Pricing

When power is injected into the grid by suppliers, whether fossil fuel, renewable, or an alternative power source, not all of the power reaches consumers. Some of the power is lost during transmission because the movement of electrons produces heat in the transmission lines. To complicate matters, the amount of power lost in moving energy over a transmission line depends on physical properties of the line such as resistance, reactance, voltage levels, loading of the line, and ambient temperature. The losses incurred in transmitting power from a specific supply location to serve a specific customer depends on the many ways the power moves over different transmission lines from supply source to load sink.[40] Supply sources that are located at different points on the grid will incur different levels of losses in serving an

[38] A later section contains a brief discussion of the need to examine the level of transmission constraint penalty factors (shadow prices) as a step in lessening the gap between the cost of out-of-market actions and the avoided cost of loss of load events.

[39] An equivalent approach would be to increase the "X" factor by the amount of the out-of-market capacity.

[40] Hogan, William, "Networks for Electric Power Transmission: Technical Reference," February 1992; available at: https://www.hks.harvard.edu/fs/whogan/acnetref.pdf.

increment of load at a specified location. In order to compare the incremental and total losses of different supply and load configurations, a standard measure called a "penalty factor," or its mathematical equivalent, a "marginal-loss factor",[41] quantifies the marginal losses incurred in serving an increment of load at a reference bus from different locations. The marginal-loss factor is not a constant for the system as a whole or for any location. In particular, it increases with increasing transmission system flows, so that the marginal losses incurred in serving an increment of system load are always larger than the average losses. To a first approximation, losses increase in proportion to the square of power flows. It is standard practice in all of the ISOs regulated by the Federal Energy Regulatory Commission to take marginal losses into account in both the least cost economic dispatch and locational pricing.[42]

By dispatching generation to meet load at least cost, including the cost of losses, system operators eliminate a material source of inefficiency and have achieved substantial cost savings. In a 2007 report, PJM estimated savings of $100 million per year through energy and congestion costs, and of over 3,600 MW during peak hours as a result of including marginal losses in dispatch and pricing.[43] The Federal Energy Regulatory Commission (FERC) explained the savings clearly in an Order supporting the implementation of marginal-loss pricing in the CAISO:

> For example, if the marginal losses to deliver energy from a remote generator to a customer at another location are 10 percent, then in order to deliver 1 MWh to the customer, the remote generator must produce 10 percent more, or 1.1 MWh of energy. If the remote generator's marginal cost to produce 1 MWh is $50, then the marginal cost of delivering 1 MWh of energy to the customer is $55 (i.e., the marginal cost of producing 1.1 MWh). Suppose that the customer could be served with energy either from the remote generator or from a local generator whose losses would be de *minimus* and whose marginal production cost is $53/MWh. If the buyer fails to consider, and is not required to pay for, losses, the remote generator would appear to be cheaper, since its marginal production cost (of $50/MWh) would be lower than the $53/MWh marginal production cost of the nearby generator. However, when marginal losses are

[41] The incremental or marginal-loss factor for a bus is the change in system losses due to a change in generation at the bus. A loss penalty factor is used to modify the incremental cost of each supplier so as to include the effects of losses. The penalty factor is the inverse of 1 minus the marginal-loss factor.

[42] "The locational marginal-loss provision is consistent with similar tariff provisions in other RTO tariffs and with the efficiency goals that underpinned the Commission's approval of those provisions, including the Midwest ISO, the NYISO, and ISO-NE." FERC, "Order on Complaint Requiring Compliance with Existing Tariff Provisions and Related Filings," May 1, 2006, paragraph 22, available at: https://www.ferc.gov/CalendarFiles/20060501180437-EL06-55-000.pdf. For a recent review of marginal-loss pricing in the FERC jurisdictional ISOs, see Eldridge, O'Neill and Castillo, "Marginal Loss Calculations for the DCOPF," January 24, 2017, available at: https://www.ferc.gov/legal/staff-reports/2017/marginallosscalculations.pdf.

[43] PJM, "Marginal Losses Implementation Training," Winter and Spring 2007, Version 1, p. 10.

> considered, the nearby generator would be the more efficient source. That is because the marginal cost of delivering energy to the customer from the nearby generator would be about the same as the marginal production cost of \$53/MWh (since losses would be *de minimus*), while the full marginal cost to deliver energy from the remote generator would be higher, i.e., \$55/MWh. Thus, in determining what supply sources can most efficiently serve customers, the cost of marginal losses should be considered. Failure to consider marginal losses – or to understate marginal loss costs – can inefficiently inflate the total cost of serving load.[44]

Dispatching in order to minimize the cost of meeting load, including transmission system losses, is accompanied by locational pricing that reflects the differences in marginal losses for different supply sources. When incremental supply from a generator decreases losses in serving load, the generation is more valuable, and its locational price will increase in proportion to the loss penalty factor (which will be greater than one). Conversely, supply that results in an increase in system losses will look relatively less attractive in the dispatch; the generation will have a lower locational price and will be dispatched to a lesser extent than if marginal losses were not taken into account. With marginal-loss pricing, the locational price at each location reflects not only the marginal impact on congestion from an increment of load at the bus, but also the marginal impact on system-wide losses.

> Billing on the basis of marginal costs ensures that each customer pays the proper marginal cost price for the power it is purchasing. It therefore complements and reinforces PJM's use of LMP to price electricity.[45]

The PJM experience illustrates the relative importance of marginal losses. As shown in Figure 13, marginal losses in total are comparable in importance to congestion costs.

[44] FERC, "Order On Further Development of The California ISO's Market Redesign and Establishing Hearing Procedures," June 17, 2004, paragraphs 142 and 143, available at: https://www.ferc.gov/whats-new/comm-meet/061704/E-2.pdf.
[45] May 1, 2006 Order, paragraph 4, available at: https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=11016260.

Figure 13

Total PJM Costs
Congestion and Marginal Losses (2009-2016)

	Cost ($ Millions)		Percent of PJM Billing	
Year	Congestion	Marginal Losses	Congestion	Marginal Losses
2009	$719	$1,268	2.7%	4.8%
2010	$1,423	$1,635	4.1%	4.7%
2011	$999	$1,380	2.8%	3.8%
2012	$529	$982	1.8%	3.4%
2013	$677	$1,035	2.0%	3.1%
2014	$1,932	$1,466	3.9%	2.9%
2015	$1,385	$969	3.2%	2.3%
2016	$1,024	$697	2.6%	1.8%

Source: Monitoring Analytics, LLC, "2016 State of the Market Report for PJM: Section 11: Congestion and Losses", March 2017

ERCOT currently does not take into account the marginal-loss factors for different supply sources in operating its security constrained economic dispatch. In ERCOT, the load forecast for each location on the grid includes an estimate of losses and ERCOT performs a security constrained dispatch of generation to serve load plus losses using a lossless transmission model.[46] The dispatch does not account for differences in the cost of the marginal losses that will be incurred in serving load from one supply source versus another.

Instead of charging prices that reflect marginal losses, the actual cost of losses is averaged and socialized to all load. Section 13 of the ERCOT Nodal Protocols explains the procedures ERCOT uses to allocate both transmission and distribution level losses to the load obligation of Qualified Scheduling Entities (QSEs), who are responsible for procuring additional supply for

[46] ERCOT Nodal Protocols, Section 13.1.1, September 1, 2016.

their loads to cover the allocation of losses.[47] The QSE obligation to self-supply losses or purchase energy to cover them is included in the ERCOT settlements for loads.

The lack of marginal-loss pricing is a significant matter in ERCOT, where setting prices to accurately reflect locational differences is central to the energy-only market design. Marginal-loss pricing reform will have a beneficial impact and ensure that the cost-causation principle is better expressed to resources to provide more efficient retirement decisions and more efficient siting of future generation.

Using another way to illustrate the significance of this missing market design element, Figure 14 summarizes the marginal-loss component of prices for each of the New York Independent System Operator (NYISO) zones in a high load interval and a low load interval. In both periods, the marginal-loss component results in a significant difference in the locational price for suppliers that are located remotely from load versus those located closer to load. In the high load interval, for example, the loss component leads to a difference of \$4.63 per MWh (\$3.3 + \$1.33) in the locational price paid to a supplier in Zone J (New York City), versus Zone D (North).[48] In the low load interval, this price difference falls, to \$2.48 per MWh, but is a substantial 15.2% of the reference bus price. Figure 15 shows the location of these load zones in New York State.

The implications of marginal-loss pricing for Texas should be clear where CREZ enables renewable power from the northwest to serve load in other regions of the state. If the marginal-loss components of prices were of the same order of magnitude as those observed in the NYISO, the locational prices in Houston could and should exceed those in the west by \$2 to \$4 in every hour, even when transmission constraints are not active.

[47] *Id.*

[48] The impact of marginal losses is stated as a difference in the loss component of the price difference between two locations, as this is invariant (although there is a second-order effect) to the choice of the reference bus. The absolute value of the marginal-loss component (and congestion component) at a bus will change with a change in the reference bus, because the reference bus price, penalty factors and shift factors all change.

Figure 14

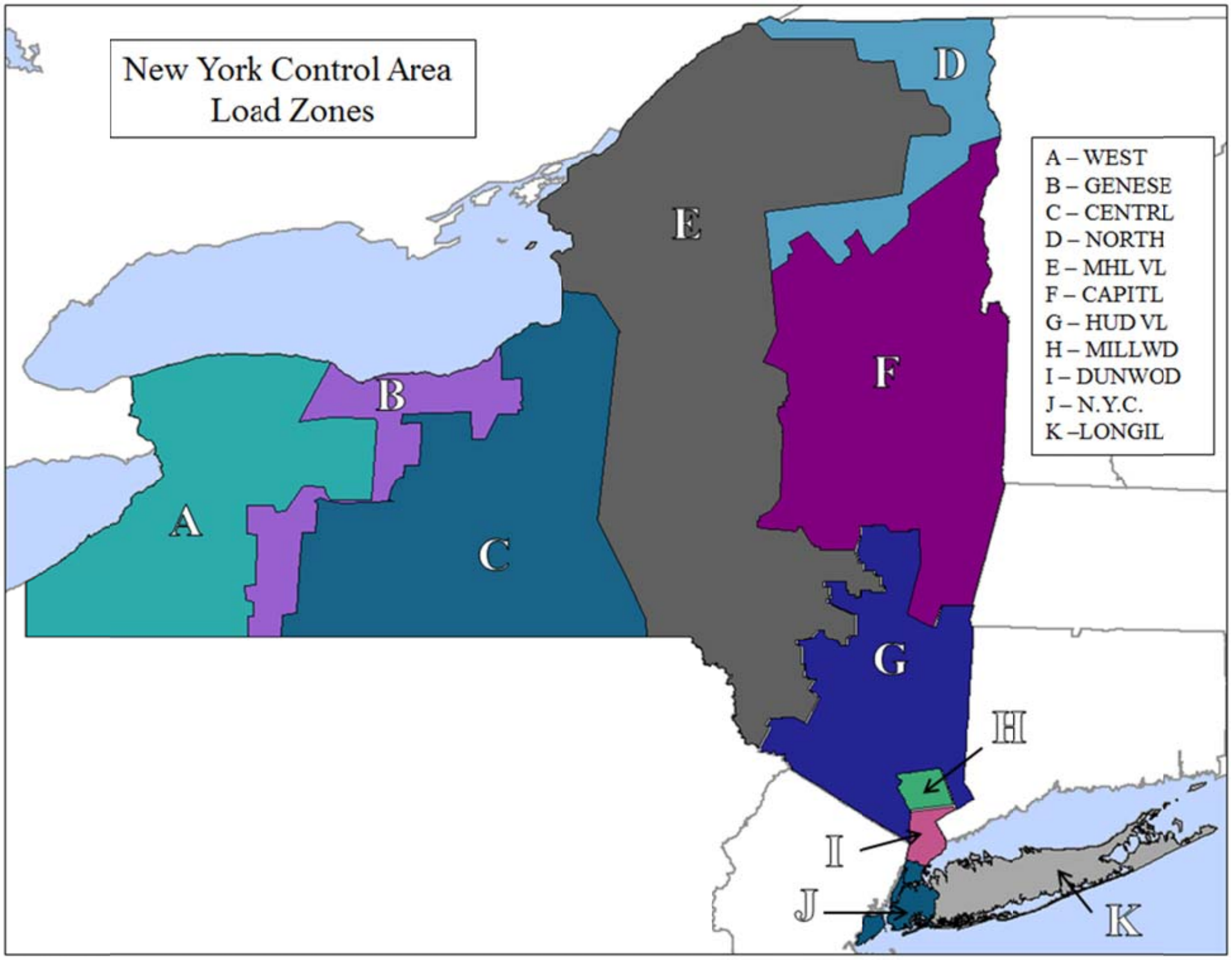
Zonal Loss Components ($/MwH)
High and low load intervals on 7/13/2016

Zone	High Load Interval	Low Load Interval
Reference Bus LBMP	40.19	16.31
A - WEST	0.8	0.21
B - GENESE	1.85	0.23
C - CENTRL	1.2	0.33
D - NORTH	-1.33	-0.75
E - MHK VL	1.85	0.47
F - CAPITL	2.93	1.16
G - HUD VL	3.46	1.53
H - MILLWD	3.46	1.58
I - DUNWOD	3.22	1.58
J - N.Y.C.	3.3	1.73
K - LONGIL	3.58	1.78
X - H Q	-1.33	-0.57
X - NPX	2.53	1.32
X - O H	-0.48	-0.03
X - PJM	0.8	0.64
Interval	7/13/2016 15:05	7/13/2016 4:00
NYISO Load MW	28,049.2	16,767.7

Note:
H Q, NPX, O H and PJM are external zones
Load total is for internal zones only

Source:
NYISO Real-time actual load data, available at:
http://www.nyiso.com/public/markets_operations/market_data/load_data/index.jsp
NYISO Real-time LBMP, available at:
http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp

Figure 15



Transmission congestion costs can be quite volatile, but the large price impacts happen in only a fraction of the total hours of the year. By contrast, the importance of marginal losses arises from the simple fact that they are relevant in every hour of the dispatch. This is not only important for improving the dispatch, but the marginal-loss incentives add up to make them as important as transmission congestion in providing efficient incentives for retaining and siting generation in specific locations. The logic for including marginal-loss effects in dispatch and pricing is straightforward, and the evidence of its critical importance to price formation is found in the experience of other regions.

Local Price Formation Issues

In addition to the policy impacts discussed in other sections – the renewable energy PTC and ITC, lack of marginal losses, and state-mandated demand response and energy efficiency programs -- price formation in ERCOT also is affected by interactions between the energy market and actions taken by the system operator to maintain local reliability. The focus in this section will be on the locational price formation impacts of RUCs, although recent ERCOT initiatives regarding RMR units, and the *ex-ante* curtailment of exports on DC lines illustrate the potential for RUC-type pricing issues to arise in other instances in which ERCOT takes out-of-market actions related to local reliability.

The interaction between ERCOT's out-of-market actions and local market power mitigation rules has become visible in the search for answers to the question of why some generation units are experiencing low energy-only returns, and why the ORDC has remained consistently low over the last year, despite the need for the same units to provide for system reliability, as evidenced by ERCOT starting them through the RUC process. The answer appears to lie in a gap in the market rules: the current ORDC mechanism compensates suppliers when there is only an RTO-wide scarcity of operating reserves, and the mechanisms in ERCOT for pricing and compensating suppliers for local scarcity are limited, which is generally the trigger for a RUC. In fact, under the current market rules, the opposite occurs, as the combination of RUC and local market power mitigation rules reduce prices, in contravention of the outcome logically expected in an energy-only market with scarcity pricing, when ERCOT brings units on-line to manage constraints. There is clear inconsistency between the objectives of the energy-only market, to employ prices to maintain reliability, and the use of out-of-merit actions rather than prices to resolve local reliability problems. The increasing frequency of RUCs, like the recent discussion of the possible need for RMR units, is a signal of reliability issues that are not being adequately reflected in real-time prices.

Following a review of the issues leading to a lack of local scarcity pricing in ERCOT, this section describes the following priorities for improvement:

- **Out-of-Market Actions to Manage Transmission Constraints**: Local scarcity pricing and mitigation rules require changes to properly set prices when there are reliability unit commitments or other ERCOT reliability actions to manage transmission constraints; these changes should not disable rules for local market power mitigation.
- **Dispatch and Pricing for Local Reserve Scarcity:** The introduction of local reserve requirements, implemented through co-optimization, would provide a market solution to properly set prices when there are constraints on reserve availability in a sub-region.

LACK OF SCARCITY PRICING WITH RELIABILITY UNIT COMMITMENT

A RUC is an out-of-market action taken by ERCOT when it determines that the set of units that are on-line and operating in the market, or that can be brought on-line, are not sufficient to meet its operational reliability criteria. ERCOT assesses the reliability of its unit commitment following the completion of the day-ahead market, and thereafter hourly up to the time of the real-time dispatch; it is of no significance to this evaluation whether units are self-committed or committed in the day-ahead market, because the need for a RUC is based only on the forecast of the physical operating status of the system, load, and other variables at the time of real-time dispatch. If ERCOT's software determines that the power flow will not otherwise meet its reliability criteria, it produces a set of recommended resource commitments. ERCOT operators review these recommendations and decide whether or not to execute them, and may also manually select resources to commit through a RUC, introducing transparency concerns.[49]

The number of days on which RUC commitments occurred increased from 70 in 2015 to 269 in 2016, while the number of hours in which resources responded to RUC instructions from ERCOT increased from 411 in 2015 to 1,514 in 2016.[50] This recent increase in out-of-market RUC commitments is a cause for concern, as it indicates that energy-only market mechanisms are increasingly insufficient, on their own, to maintain system reliability. Over the last year, most RUCs occurred to address shortages of generating capacity in a specific location in the event of an n-1 contingency. They occurred with regularity when there were scheduled transmission outages north of Houston or scheduled or unplanned equipment outages potentially causing overloads in the area of the Rio Grande Valley. Approximately 98% of the RUC-hours addressed transmission congestion, primarily in the North and Houston zones, while only 33 hours arose to address capacity shortages. No RUC commitments occurred because of ancillary service shortage, voltage or reactive support, system inertia, anticipation of extreme cold weather or startup failures, according to ERCOT.[51] Although ERCOT reports the reliability condition giving rise to a RUC,[52] there can be a lack of clear association between the reported cause and the

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[49] ERCOT, "Overview of the Reliability Unit Commitment Process," October 14, 2016, available at: http://www.ercot.com/content/wcm/key_documents_lists/87633/5_-_Overview_of_the_RUC_Process_for_QMWG_-_Final.pptx

[50] ERCOT, "Annual TAC Review of the Market Impacts of Reliability Unit Commitments," January 26, 2017, p. 11, available at: http://www.ercot.com/content/wcm/key_documents_lists/107846/14._2017_Annual_TAC_Review_of_the_Market_Impacts_of_RUCs_-_Final.pptx

[51] *Id*.

[52] ERCOT, "Annual TAC Review of the Market Impacts of Reliability Unit Commitments," January 26, 2017, available at: http://www.ercot.com/content/wcm/key_documents_lists/107846/14._2017_Annual_TAC_Review_of_the_Market_Impacts_of_RUCs_-_Final.pptx

RUC action, giving rise to questions about whether RUC actions occur for additional reasons, such as to protect against an n-1 or n-2 event.[53]

Following the logic that a RUC-committed unit is not running voluntarily, but is rather running because it is required for reliability, its energy market offer is set to the greater of the ERCOT RUC offer floor of $1,500 per MWh or its submitted energy offer curve (if any).[54] However, during instances when a RUC alleviates local congestion, the $1,500 offer is often mitigated to a lower price because the RUC unit fails ERCOT's test of local market power. When this occurs, the $1,500 per MWh default RUC offer is mitigated using an offer cap typically based on the verifiable cost of the RUC-committed resource plus a modest adder.[55] As discussed below, while this mitigation follows ERCOT protocols for managing the potential for the exercise of local market power, it has the potential to extinguish the ability of the unit to earn a return for scarcity.[56]

The introduction of a RUC-committed unit's minimum generation block into the generation dispatch stack decreases locational prices through its impact on the congestion component of prices. A RUC-committed unit immediately comes on-line and ramps to its lower sustainable limit. If the RUC unit's energy offers are not mitigated for local market power, they will remain at $1,500 and the RUC-committed unit will rarely be dispatched above its low sustainable limit and its offer price of $1,500 will not set the locational price. The RUC-committed unit is said to be "pinned" at its low sustainable limit. It will rarely be dispatched to meet an increment of load because of its $1,500 offer price, so its offer does not enter into locational price formation. Instead, in the absence of local market power mitigation, the locational prices generally will be based on the offer prices of one or more lesser priced supply (or dispatchable demand) alternatives. These price-setting units are often those that have been dispatched down to accommodate the minimum load block of the RUC-committed unit: their offer price for being dispatched up (again) is marginal for price formation.

[53] Nodal Protocols, 5.5.1 (5). "ERCOT shall analyze base configuration, select n-1 contingencies and select n-2 contingencies under the Operating Guides. The Operating Guides must also specify the criteria by which ERCOT may remove contingencies from the list. ERCOT shall post to the Market Information System (MIS) Secure Area the standard contingency list, including identification of changes from previous versions before being used in the Security Sequence. ERCOT shall evaluate the need for Resource-specific deployments during Real-Time operations for management of congestion consistent with the Operating Guides."

[54] Nodal Protocols, 6.5.7.3 (c).

[55] ERCOT, "Nodal Protocols Section 4: Day-Ahead Operations," April 5, 2017, Section 4.4.9.4.1 (c); the mitigated offer is the greater of 10.5 MMbtu/MWH times the gas reference price, or the resource's verifiable offer cost plus the verifiable variable O&M cost times a multiplier.

[56] In situations of extreme scarcity, the price might rise to more than $1,500 per MWh, despite the mitigation of the offer price of a RUC-committed unit.

A specific concern arises when a RUC commitment occurs to resolve a modest or relatively short-term transmission element overload. When this occurs, the dispatch of the RUC-committed unit will likely remain pinned to its low sustainable limit, because not all of its minimum load block capacity is needed to resolve the constraint, and its incremental offer price is set at the cap of $1,500. Pinning will occur throughout the minimum run time of the RUC-committed unit, even if the unit is needed to resolve a constraint for only a portion of this time. RUC commitments can primarily to resolve modest transmission constraint violations because ERCOT's software assigns a very high penalty factor to the violation[57] and the software will search for any solution to relieve the constraint, even a generation unit with only a small shift factor with respect to the constraint violation. Thus, the ERCOT market bears the cost of committing a unit to provide a modest counterflow to resolve a situation with a low value of lost load, and the price formation treatment of the RUC-committed unit suppresses locational prices through the addition of the minimum load capacity to the dispatch stack, combined in many cases with mitigation of the offer prices of the RUC-committed unit.[58] ERCOT recently lowered the RUC penalty factors following discussion with stakeholders but it remains to be seen if the lower values will remedy the situation.[59] The price adjustment to the ERCOT system lambda for RUC minimum capacity through the Reliability Deployment Price Adder will not compensate for the suppression of the congestion component of the local price.

If the RUC-committed unit is dispatched above its low sustainable limit, in principle it could set a locational price of $1,500 until it reaches its upper operating limit, but this will only happen in the circumstance in which the energy offer costs of the unit are not mitigated for local market power *and* the unit is dispatched above its low sustainable limit. In other words, the $1,500 price will be reached only when a RUC unit is so effective in resolving a constraint or when region-wide capacity is so scarce that it is dispatched above its low sustainable limit despite an offer cost of $1,500, yet it passes ERCOT's local market power test.

Thus, out-of-market RUC commitments, which may increasingly be occurring as a symptom of low energy-only prices, are unlikely to result in prices that signal the local scarcity issue triggering the RUC. Rather, the RUCs, often in combination with market power mitigation, suppress prices and perpetuate a cycle of reliance on out-of-market actions, rather than market responses, to maintain local reliability.

[57] ERCOT " Maximum Shadow Prices in RUC: Initial Results," January 30, 2017, available at: http://www.ercot.com/content/wcm/key_documents_lists/113924/Analysis_of_RUC_max_shadow_prices_initial_results.pptx

[58] See NPRR626 "Reliability Deployment Price Adder (formerly "ORDC Price Reversal Mitigation Enhancements")".

[59] ERCOT, "W-A040617-01 Changes to transmission constraint Shadow Price caps," Operations Notice to ERCOT Market Participants, April 6, 2017.

Local Market Power Mitigation of RUC Units Ignores Local Scarcity Value

ERCOT conducts local market power mitigation through a process called the "Texas Two Step" because it is based on two Security Constrained Economic Dispatch (SCED) runs. Prior to the first run, ERCOT identifies competitive and non-competitive constraints using its constraint competitiveness test, which evaluates a market participant's ability to exercise local market power through economic or physical withholding. In the first step, SCED observes only the limits of competitive constraints to calculate initial reference prices. In the second step, the SCED process observes the limits of both competitive and non-competitive constraints, and mitigates offers to the greater of the reference prices produced in step one (adjusted by a variable not to exceed 0.01 multiplied by the resource's mitigated offer cap) or a resource's mitigated offer cap.[60]

Imposition of offer caps based on verifiable costs (plus a modest adder) for local market power mitigation is inconsistent with compensating suppliers for the scarcity value of their output during times when generation units are committed through the RUC process. RUC units have been committed by ERCOT because they are needed, in the absence of alternative economic offers, to prevent the power flow from violating a reliability constraint. From this perspective, it is apparent that the RUC-committed unit is providing a scarce resource and, in the absence of a determination of local market power, the RUC energy offer is set to $1,500 as a consequence.[61] But, if the same unit is determined to have local market power, its offer is reduced, as described above, to a price near its costs and it will set price whenever it is dispatched up for incremental energy at this relatively low offer price.

The graphic in Figure 16 illustrates the impact of market power mitigation on the price and dispatch of a Calpine generation unit for 17 hours during a time when it receives a RUC instruction from ERCOT in order to relieve a transmission constraint into the Rio Grande Valley area. The blue line on the figure is the real-time settlement point price for the unit during each interval, including the ORDC and Reliability Deployment Price Adder. The orange line is the dispatch level of the unit and reflects high and low scheduling limits that vary depending on its operating configuration (either 1x1 or 2x1).

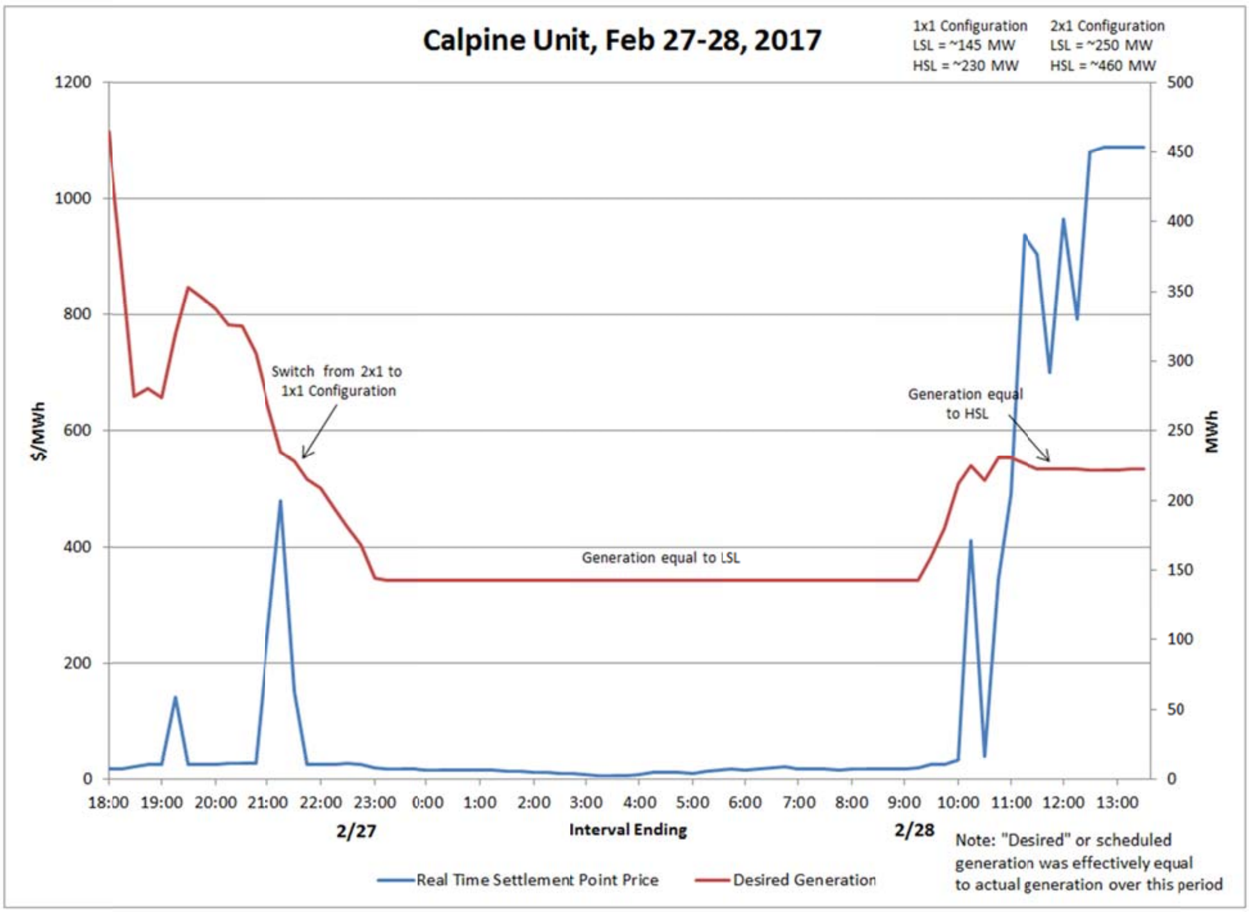
The figure shows, first, that the settlement price for the unit during the period of its RUC is far below the $1,500 per MWh offer price floor for a RUC unit. In about half of the intervals, the

[60] ERCOT, "Nodal Protocols Section 6: Adjustment Period and Real-Time Operations," January 1, 2017, p. 58. The offer caps of units subject to local market power mitigation are the lower of their verifiable costs or the product of a gas price index multiplied by a predetermined heat rate (10.5). ERCOT, "Nodal Protocols Section 4: Day-Ahead Operations", April 5, 2017, Section 4.4.9.4.1 (c).

[61] ERCOT, "Module 5: Reliability Unit Commitment," p. 31, available at: http://www.ercot.com/content/wcm/training_courses/44/M5___Set301___RUC___Dec2014.pdf.

settlement price hovers around $27/MWh (starting just before midnight on 2/27 and extending until just after 8:00 am on 2/28). When the settlement point price rises above the mitigated offer price of the unit during the RUC period, the unit is dispatched above its lower scheduling limit; this can be seen, for example, in the figure where the settlement price rises at the same time as the dispatch of the unit increases starting at 9:15 on 2/28. In the period immediately following the first RUC instruction at 18:00 on 2/27, the unit was also mitigated for market power and dispatched up in many intervals at market prices far below $1,500. During the intervals when the unit is dispatched above its lower scheduling limit based on its mitigated offer price, the incremental energy available on the unit is made available to meet load, displacing other suppliers at an offer price that is below the $1,500 default offer price.

Figure 16



The situation shown in Figure 16 was repeated during many hours in 2016. In 170 of the RUC hours in 2016, ERCOT reported that the committed resource was dispatched above its minimum load level and, in principle, could have been marginal for purposes of price formation. However, in 127 of these hours, the offer price of the RUC resource was subject to market power mitigation and, as a result, the locational price for the resource was less than its RUC offer floor although the unit was needed for reliability. In another 39 of these hours, the LMP was less than the RUC offer floor even though the RUC resource was not mitigated for market power.[62]

RUC-committed capacity appears to be, in almost all instances, a substitute for transmission, as it provides counterflow on a constraint to increase transmission capacity in the opposite direction. However, when pinned at its low sustainable limit and/or with its offer costs reduced because of market power mitigation rules, the RUC-committed capacity is not paid a price reflecting transmission scarcity or, stated a different way, the avoided cost of alternative solutions to resolving the constraint. The scarcity value of the unit's output can be related to the value of the counterflow provided on the constraint and it is doubtful that this counterflow is worth no more than the mitigated offer cost of the unit. Thus, the requirement is for a methodology to place a value on this counterflow, i.e., place a value on the relief of local scarcity, despite the imposition of local market power mitigation.

For the RUC process, price formation in ERCOT fails to simultaneously address the objectives of mitigating market power, which is necessary in an electricity market, and compensation of suppliers for the scarcity value of their capacity and energy. The impact in an energy-only market is particularly compelling because recovery of fixed costs comes entirely from the margin a supplier earns above its costs in the energy and reserve markets. Mitigation of a unit's offer at exactly the time when it is addressing a situation of scarcity eliminates the price signal required in the energy-only market to sustain this and other units in operation so that they can continue to address the same scarcity situation in the future.

Without examining the underlying efficiency of the procedures and software used for RUC, changes to price formation must be considered to ameliorate the impact of RUC commitments and local market power mitigation on pricing. The ERCOT market rules implemented by Nodal Protocol Revision Request (NPRR) 626 intended to address the impact of the extra capacity of RUC-committed units on system energy prices, and the ORDC was implemented for scarcity pricing, but neither of these tools assigns a value to the relief of local scarcity.

Reliability Deployment Price Adder (NPRR 626) Does Not Price Local Scarcity Value

The Reliability Deployment Price Adder implemented in August 2014 does not attribute local scarcity value to capacity deployments occurring to relieve local reliability problems. The Reliability Price Adder is intended to relieve the energy price suppression arising from out-of-market actions the system operator may take to maintain reliability, including the deployment

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[62] ERCOT, "Annual TAC Review of the Market Impacts of Reliability Unit Commitments," January 26, 2017, p. 7, available at: http://www.ercot.com/content/wcm/key_documents_lists/107846/14._2017_Annual_TAC_Review_of_the_Market_Impacts_of_RUCs_-_Final.pptx

of Emergency Response Service, RMR committed units, RUC-committed units, and load resources other than controllable loads.[63] The implementation of this adder, however, estimates only the impact of these reliability deployments on the level of the ERCOT system-wide price (i.e., system lambda), as measured by the change in the reference price component of the LMP.[64] It does not confer value to reliability actions causing changes in relative locational prices within ERCOT, as measured by changes in the congestion components of LMPs in different locations.[65] A RUC commitment and other reliability deployments may decrease prices in a local area, due to relieving a transmission constraint, for example, yet have little or no effect on prices outside of this local area, so that the estimated change in the system reference price will often be close to zero.

There are problems with the Reliability Deployment Price Adder even for the limited purpose of estimating the region-wide price effect, when the resource deployed for reliability is dispatched based on its offer. When its offers are mitigated, a RUC-committed unit may be dispatched above its lower operating limit, because its mitigated offer leads it to displace the dispatch of other higher-price resources. However, the methodology for estimating the Reliability Deployment Price Adder excludes only the capacity of the unit's low sustainable limit, so that the re-estimation of prices and calculation of the adder does not take into account the full quantity of energy dispatched from the RUC-committed unit.[66]

ORDC Does Not Price the Scarcity Value of RUC Units

The current ORDC does not correctly price regional scarcity when there is a RUC and, by design, it does not produce a price signal for local scarcity. The ORDC provides a principled basis for pricing region-wide scarcity, but when a RUC occurs (or an RMR), the measurement of the Real-Time On-Line Reserve Capacity used to calculate the ORDC scarcity price is distorted by the inclusion of the RUC capacity.[67] The ORDC price adder should rise when there is increased scarcity, but if a RUC reduces this scarcity by increasing the quantity of available reserves as

[63] NPRR 626, "Reliability Deployment Price Adder," August 12, 2014.

[64] Nodal Protocols, April 1, 2017, Section 6.5.7.3.1 (2) (j).

[65] Note that the methodology for calculating the Reliability Deployment Price Adder appears to depend on the definition of the system reference bus. Depending on the location of the reference bus, the change in prices from a change in unit commitment could appear as a change in the reference bus price or a change in the congestion component at a bus. For example, if the reference bus were at the location of a deployed RUC unit, the reference price would change, not the congestion component, where as if the reference bus were in a different place, the change would likely be to the congestion component. This does not appear to be an issue in ERCOT because of the use of a distributed reference bus.

[66] Nodal Protocols, April 1, 2017, Section 6.5.7.3.1 (2) (a).

[67] The calculations of Real-Time On-Line Reserve Capacity and Real-time Off-Line Reserve Capacity are not reduced as a result of a RUC or RMR activation. ERCOT, "Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder," Version 1.3 accessed on April 6, 2017.

measured by Real-Time On-Line Reserve Capacity, the ORDC price adder will fall (or stay the same), rather than rise. ERCOT supply will increase by the amount of the minimum load of the RUC or RMR committed unit. Additionally, if the offer of the out-of-market committed unit is mitigated because of the potential for local market power, the unit may be dispatched above its minimum load level, further adding to supply and depressing prices. When ERCOT initiates a RUC prior to the development of scarcity, it thus may forestall the development of a price signal to induce market-based solutions to such scarcity.

The current ORDC also does not price local scarcity in general. Therefore, if there is an adequate supply of reserves region-wide, but a shortage in a particular region, the ORDC will remain low. When a RUC is triggered by a local transmission constraint and there are concurrently sufficient reserves region-wide, the ORDC by design will not produce a scarcity price signal. This is almost always the case. In January 2017, ERCOT reported that 97.8% of the RUCs in 2016 occurred to address transmission congestion, and only 2.2% for capacity insufficiency.[68] In these cases when the RUC occurred, the overall system was not short of reserves, so the ORDC adder did not apply and there was no mechanism to ensure appropriate pricing of local scarcity.

OTHER LOCAL RELIABILITY ACTIONS HAVE PRICE IMPACTS

Activation of Reliability Must-Run Units

ERCOT activation of a generation unit contracted under an RMR agreement has the same potential impact on price formation as a RUC, due in large part to the confounding effect of local market power mitigation. When an RMR unit is activated to serve a reliability need, it indicates the need for local scarcity pricing since the presence of an RMR unit signals a shortage of supply in a particular region. Prices in the local area of an activated RMR unit should rise, not fall. However, since RMR units address local problems, the units will often fail market power screens. Given the local market power, ERCOT mitigates the offer price. The result is that the increased out-of-market capacity produces lower, not higher, prices. This distortion to price formation affects the dispatch and prices for all other units in the local area, not just the RMR unit. If mitigated, offers for RMR units should reflect the penalty value of resolving the constraint so as to not disturb the price signal.

RMR agreements occur when a generation unit announces its intention to exit the ERCOT market, but ERCOT determines it must remain in service for a period of time because there is a

[68] ERCOT, "Annual TAC Review of the Market Impacts of Reliability Unit Commitments," January 26, 2017, available at: http://www.ercot.com/content/wcm/key_documents_lists/107846/14._2017_Annual_TAC_Review_of_the_Market_Impacts_of_RUCs_-_Final.pptx.

shortage of supply in the location of the unit to provide voltage support, stability, or management of transmission constraints.[69] The energy offers of RMR units are set at the ERCOT system-wide offer cap ($9,000/ MWh) because the units are activated when the system operator has no other available market alternative to maintain reliability.[70] Setting the RMR offer price at the cap is also intended to insure that incremental dispatch of the RMR unit above its lower scheduling limit does not displace the dispatch of other resources. As long as the RMR unit remains at its low sustainable limit, other resources will determine the energy price outcome, and ERCOT also estimates the Reliability Deployment Price Adder with the intention of augmenting prices to offset the impact of the RMR unit's minimum generation.[71]

However, mitigation of the offers of activated RMR units not only eliminates the scarcity pricing intended by the default offer of $9,000/MWh, but it will also result in the RMR unit being incrementally dispatched, displacing other suppliers, and setting a price equal to its mitigated offer cost. The way that this price distortion occurs is identical to what has been described for RUC-committed units. When an RMR unit is activated it is deemed to be the only resource available to solve a reliability constraint, so the expectation is that the offers of RMR units will be mitigated for local market power.

Debate over the offer price for the recently terminated RMR agreement with NRG's 371 MW Greens Bayou Unit 5 exposed the potential impact of RMR agreements on ERCOT prices. ERCOT determined that the Greens Bayou Unit 5 would be needed for the peak months of 2016 and 2017 to alleviate overloads on the Singleton to Zenith lines north of Houston until the completion of the Houston Import Project in 2018.[72] However, under the ERCOT market rules, the ERCOT Independent Market Monitor estimated that the mitigated offer price of the unit at

[69] Nodal Protocols, Section 3.14.1, April 5, 2017.

[70] PUCT Substantive Rule §25.505.

[71] The Reliability Deployment Price Adder does not include a locational component, so does not value the suppressing effect of the minimum load block on LMPs in the area local to the RMR unit.

[72] ERCOT Nodal Protocols, Section 22, Attachment B: Standard Form Reliability Must-Run Agreement, April 1, 2015, available at: http://www.ercot.com/content/wcm/lists/89476/Reliability_Must_Run_Agreement___NRG_Texas_Power_LLC_and_ERCOT___Effective_Date_06_01_2016__Fully_Executed___003_.pdf") and http://www.ercot.com/content/wcm/lists/89476/2016_Constraints_and_Needs_Report.pdf. The ERCOT Board had the option to extend the program through June 2018, which it did on June 14, 2016, before subsequently terminating the agreement effective May 29, 2017. See http://www.ercot.com/services/comm/mkt_notices/archives/1219. Under the agreement, ERCOT paid NRG a standby payment of $3,185 per hour to be available. See http://lists.ercot.com/scripts/wa-ercot.exe?A3=ind1606&L=NOTICE_CONTRACTS&E=quoted-printable&P=7446. ERCOTT completed RMR studies in the fall of 2016 and determined that Greens Bayou Unit 5 would be needed to support transmission system reliability until the Colorado Bend II Generating Station begins operation. With a change in the expected operational date for the Colorado Bend II Station to June 2017 from July 2017, the RMR agreement with Greens Bayou Unit 5 is no longer needed for the peak months of 2017. See http://www.ercot.com/news/releases/show/120278.

the time was "likely to be roughly $50 per MWh."[73] The Independent Market Monitor supported the concern that, at this price, the RMR unit could be incrementally dispatched and set price in advance of other sources of supply.[74]

RMR contracts signal a problem with energy-only pricing. By suppressing prices and shifting costs out of the market (through the per hour availability payment), they perpetuate a cycle in which reliability problems are addressed by transmission solutions or more RMR contracts or RUCs because there is inadequate price incentive for solutions proffered by private market investors.

In addition to providing a local scarcity price signal that is not extinguished by market power mitigation, there is a need to ensure RMR contracts are not invoked unnecessarily because of the assumptions used to evaluate the necessity for the contracts. For example, prior to the passage of NPRR 788 in October 2016, the market rules directed ERCOT to use "the regional Load value provided by the appropriate Transmission Service Provider (TSP) as part of the annual Steady State Working Group (SSWG) study case development process" as the assumption for load in the local RMR area.[75] The SSWG load forecasts are for six years in the future,[76] which is well beyond the maximum two-year time horizon for consideration of an RMR solution to a reliability issue. NPRR 788 addressed this bias toward RMR solutions by applying more appropriate operational reliability criteria to the RMR evaluation and requiring the use of load forecasts from the current regional transmission plan.[77]

When prices are suppressed, as a result of mitigation of the offer price of an activated RMR unit, they do not reflect the scarcity value of capacity in the locality of the unit. The prices are inconsistent with the foundational objective of the ERCOT market to formulate energy prices to support necessary investments in existing and new resources. Moreover, the presence of an RMR unit, even when not activated, will tend to suppress prices, as day-ahead prices and forward contracts will be discounted based on assessments of and uncertainty about the

[73] Garza, Beth, "NPRR Comments," NPRR 784, Mitigated Offer Caps for RMR Units, June 15, 2016, available at: http://www.ercot.com/content/wcm/key_documents_lists/98406/784NPRR_03_IMM_Comments_061516.doc

[74] Both the IMM and NRG support NPRR 784, which would have required ERCOT to "set the Mitigated Offer Cap curve equal to the highest value (in $/MWh, not exceeding SWCAP) that is expected to allow SCED to Dispatch the RMR Unit." (see NPRR 784, June 1 2016). For Greens Bayou, these estimates were as high as $700/MWh. Beth Garza, "NPRR Comments," NPRR 784, July 26, 2016.

[75] Nodal Protocols, Section 3.14.1.

[76] ERCOT, "Steady State Working Group Procedure Manual," February 3, 2016, available at: http://www.ercot.com/content/wcm/key_documents_lists/27292/SSWG_Procedure_Manual.Approved_by_ROS_20160203.docx.

[77] "Board Report," NPRR 788, RMR Study Modifications, October 11, 2016. NPRR 788 also sets requirements for the minimal required shift factor of an RMR unit on a violated constraint, the minimal constraint violation required for an RMR agreement, and assumptions on generation in-service in the power flow analysis.

probability of activation and the corresponding impact of RMR offer mitigation and minimum generation output on local scarcity price formation.

Curtailment of Exports on DC Lines Based on E-Tags

ERCOT's recent, but temporary, change to its operating rule for curtailing export schedules to Mexico is a specific example of the continuing need to assess the potential for reliability rules to subvert the energy-only price signals required to encourage market-based investment, as opposed to reliance on non-market interventions like RMR and RUCs occurring in part because of the insufficiency of energy-only prices.[78]

On September 28, 2016, ERCOT changed its operating procedures regarding requests to schedule exports at its DC ties with CFE in Mexico.[79] Prior to this procedure change, ERCOT accepted e-tag schedules for the DC ties up to the physical limit of the relevant tie, even if the total schedule on the tie exceeded ERCOT's posted limit. Schedules on the tie were treated on par with ERCOT load in the dispatch, and only curtailed prior to ERCOT load in the event of system emergencies.[80]

After the procedure change, new e-tag requests were denied as soon as the sum of previously accepted e-tags reached the posted export limit, which does not necessarily bear any relationship to actual physical capability for power transfers in real-time. By prospectively denying export e-tags, and forestalling exports that would have been efficient at market prices, ERCOT avoided the possible need to declare an emergency and report the event to the North American Electric Reliability Corporation (NERC).

ERCOT's operating rule change was inconsistent with price formation in an energy-only market because it prescribed prospective actions undercutting the very price formation that would solve the reliability issues that might occur as export load rises. ERCOT would not necessarily have been approaching a situation of scarcity when it invoked the procedure change, as the rule was based on contract path scheduling limits, rather than based on an estimate of the real-time power flow. Such a reliability action preempts a market response by lowering price in advance of a potential scarcity event, rather than allowing the price to rise, reducing the incentive for supply and demand to respond. As the price rises, imports could increase, for example, to offset the scheduled exports.

[78] "Nodal Protocol Revision Request," NPRR 818, Allow Curtailment of DC Tie Load Prior to Declaring Emergency Conditions, February 2, 2017. Approved April 4, 2016, See http://www.ercot.com/mktrules/issues/NPRR818.

[79] Power Operations Bulletin #755.

[80] See Nodal Protocol 4.4.4: "DC Tie Load is considered as Load for daily and hourly reliability studies, and settled as Adjusted metered Load (AML)". Nodal Protocol 6.5.9.3.4 addresses Energy Emergency Alerts.

Actions Prior to or During Energy Emergency Alert

According to Nodal Protocols 6.5.9.3.1 and 6.5.9.4.1, ERCOT may take a number of actions, such as starting RMR units, committing additional units, or directing resources to operate at their emergency base points, to maintain reliability when it identifies levels of Physical Responsive Capacity falling below Advisory, Watch and Energy Emergency Alert levels. These actions shift the supply and demand balance and can result in reduced energy prices as well as the reduction of the ORDC scarcity price adder.

In the current ORDC design, Real-Time Online Capacity of 2,000 MW defines the level at which the value of reserves rises to the value of lost load. However, ERCOT may take out-of-market actions when it reaches a Physical Responsive Capacity of 2,300 MW (at which point it is in Energy Emergency Alert Step #1) and, because the elements of the Physical Responsive Capacity calculation do not align with the calculation of Real-Time Online Capacity, this will likely occur well before the Real-Time Online Capacity falls to 2,000 MW.[81] Because of the inconsistency between the ORDC parameters and ERCOT operating procedures based on Physical Responsive Capacity, ERCOT can use out-of-market actions to resolve reliability issues prior to the energy-only price rising substantially through the ORDC adder in order to incent market responses.

ERCOT's operating procedures appear to be inconsistent with the ORDC market design because they can diminish the price-based incentive for suppliers to respond to tight system conditions. As the ERCOT market fails to provide a scarcity price signal, suppliers will find that it is not profitable to remain in operation or to be available when needed for reliability, and when this supply is not available, ERCOT will find it increasingly necessary to take out-of-market actions, which will further reduce prices, leading to further exit of the resources required for reliability, and yet further out-of-market intervention.

If the simple structure of the ORDC continues, with the single value for "X", then out-of-market actions should accompany adjustments in the reserve values in the same way as recommended for the treatment of RUC commitments.

IMPROVEMENTS TO PRICE FORMATION FOR LOCAL SCARCITY

From the perspective of market design, there are three approaches to addressing price distortion occurring when RUCs or other out-of-market actions occur to maintain local reliability:

[81] When an Advisory is issued for PRC below 3,000 MW and ERCOT expects system conditions to deteriorate to the extent that an EEA Level 2 or 3 results, ERCOT can instruct the TSPs to reconfigure the transmission system to increase the allowed output of generation units; these actions can have a substantial impact on price formation/signals.

- Enhance price formation rules to price local scarcity occurring when RUCs and other out-of-market actions are used to manage transmission constraints;
- Enhance price formation rules to price local scarcity occurring when RUCs and other out-of-market actions (i.e. RMR) are taken to manage the impact of transmission constraints on the local deliverability of reserves during contingencies;
- Change market and operational rules to limit conditions for the system operator employing out-of-market mechanisms to address reliability constraints.

Market rule changes to enhance local scarcity price formation are preferred because they will encourage market responses to maintain reliability as an alternative to RUCs and other out-of-market actions. Market rules limiting RUCs are unlikely to be effective unless market pricing aligns with and compensates these alternative market responses to maintain reliability. Additionally, changes to system operator reporting, requiring improved documentation of the reliability constraint triggering the out-of-market action, and how the action (such as a RUC) relieves the constraint (and possibly, reporting the cost of the constraint relief) would be helpful in tempering overly-conservative out-of-market operator actions and in identifying opportunities for changes to market rules to maintain reliability while avoiding out-of-market actions, like RUCs.

Scarcity Pricing for Out-of-Market Commitments for Transmission Constraints

The normal transmission constraints used in evaluating the security of an economic dispatch solution apply, by construct, to steady-state power flows that in principle could continue indefinitely. When the normal flows are not known with certainty *ex-ante*, as must occur in forward planning and commitment, contingency analysis may identify conditions where RUC or even RMR commitments are necessary to maintain reliability in contingencies. When such a RUC or RMR commitment is made, suppression of local prices can occur, as discussed above, because the minimum load dispatch from these units depresses the locational energy prices and ORDC price adders, and local market power mitigation can additionally depress prices when the units are dispatched above minimum levels and their mitigated offer enters into price formation.

Several enhancements to ERCOT price formation should be promptly considered and could be implemented relatively quickly to reduce the effects on both local and system-wide scarcity prices when out-of-market actions occur to relieve transmission constraints. The recommendations here apply to situations when out-of-market operator actions are taken because there is uneconomic scarcity of transmission, not scarcity of region-wide or local reserves. The recommendations will be explained here for the case of a RUC, for simplicity, with acknowledgment that the details of the market rule changes might differ depending on the particular out-of-market action case.

First, the full capacity of the RUC-committed unit should be removed from the Real-Time Online Capacity used in the calculation of the ORDC adder. The full capacity of the unit is available to provide energy or reserves but was not the result of market commitment; hence, the full capacity should be removed from the Real-Time Online Capacity to leave the system-wide market-clearing price of scarcity unchanged following the RUC, as calculated by the ORDC.

Second, under the typical situation in which a RUC unit is committed to deal with normal transmission constraints active in the base case power flow or monitored contingencies (i.e. n-1), price formation needs to assign a scarcity value for the relief of the constraint(s) triggering the RUC. This requires reducing the transmission capacity of the constraints relieved by the RUC by the amount of the "but-for" counterflow created by the minimum operating level of the RUC unit. It is this counterflow that the system operator has chosen to purchase as a substitute for being able to otherwise increase the capacity of the active transmission constraint(s). In principle, the subtraction of the counterflow would occur for every possible affected transmission constraint, since the system operator, in principle, evaluates the full impact of all of the RUC unit counterflow on system reliability and cost in the decision to commit the RUC unit. In practice, it might be sufficient to decrease the limit on only the constraint driving the needed RUC commitment; this decrease would be made in only the base case power flow or the contingency in which the constraint would potentially be violated.

Third, the mitigated offer cap of the RUC-committed unit should reflect that it has been committed out-of-market in a scarcity situation. The usual logic for mitigation for local constraints is turned on its head when a unit being mitigated has been committed out-of-market for reliability and not as part of normal market operation based on bids and offers.

A simple way to address the mitigation of RUC offers in ERCOT would be to assign a value for the RUC unit's mitigated offer cap higher than its verifiable cost-based approach. The mitigated offer cap for a RUC unit should be increased to reflect the unit's value in relieving the reliability constraint but not be set so high as to reflect the exercise of local market power. An alternative approach for market power mitigation for a RUC-committed unit that may be considered in ERCOT would be a must-offer requirement with an offer cap for its minimum load level in the day-ahead market. Then, if the unit is not committed day ahead, it would establish that there has been no day-ahead physical or economic withholding, because the day-ahead model identified a cheaper commitment to serve load excluding the capped offer of the possible RUC unit. Once this is done, and a unit is not committed in the normal day-ahead market process, a subsequent RUC decision changes the fundamental condition for determining appropriate mitigated offers; mitigated offers for RUCs logically should be different than those applied to units that have not been RUC-committed because the unit is required to run for reliability. For dispatch above the minimum level, the unmitigated offer curve would provide a proxy for measuring the scarcity value that would be reflected in locational prices, since dispatch above the minimum load level is presumably not required for reliability and any incremental dispatch would be evaluated in comparison with competing offers, but this would depend on the circumstances of the case.

Mitigated offers for reliability commitments should have some workable proxy for scarcity, and the usual local market power mitigation is inappropriate. A middle ground methodology must be determined for calculating the mitigated offer cap for a RUC unit committed for local reliability, so that market prices reflect the value of the unit's output in managing transmission scarcity, but also do not allow the exercise of market power.

The scarcity pricing recommendations here apply to out-of-market commitments arising in the management of "normal" transmission constraints, where the distinguishing characteristic is that these constraints should be enforced in the normal dispatch but can be violated for short periods of time to use reserve generation outside of the constrained area to meet short-term deviations in the net-load forecast.

By contrast, any transmission constraints that must be managed both for normal power flows and utilization of reserves give rise to locational requirements for reserves and the corresponding locational operating reserve demand curves. Recommendations for this second type of local scarcity pricing follow.

Locational Scarcity Prices through Local Operating Reserve Demand Curves

Local reserve requirements, implemented day ahead and in real-time through co-optimization, would enable ERCOT to be better positioned to avoid committing additional units for reliability within the day. Implementation of real-time co-optimization of energy and reserves using the current ORDC, on its own, could enable ERCOT to better insure that a sufficient level of system-wide reserves is available in real-time.[82] However, pricing of local scarcity will require the introduction of local reserve requirements for defined zones, as well as a corresponding definition of constraints on the import and export of energy and reserves between load zones.

[82] Potomac Economics, Ltd., "2015 State of the Market Report for the ERCOT Wholesale Electricity Markets," June 2016, p. 47, available at: https://www.potomaceconomics.com/wp-content/uploads/2017/01/2015-ERCOT-State-of-the-Market-Report.pdf. "The primary reason that SASMs were infrequent was the dearth of ancillary service offers typically available throughout the operating day, limiting the opportunity to replace ancillary service deficiencies via a market mechanism. Without sufficient ancillary service offers available, ERCOT must resort to using reliability unit commitment (RUC) procedures to bring additional capacity online." "Real-time co-optimization of energy and ancillary services does not require resources to estimate opportunity costs, would eliminate the need for the SASM mechanism, and allow ancillary services to be continually shifted to the most efficient provider. Because co-optimization allows the real-time market far more flexibility to procure energy and ancillary services from online resources, it would also reduce ERCOT's need to use RUC procedures to acquire ancillary services. Its biggest benefit would be to effectively handle situations where entities that had day-ahead ancillary service awards were unable to fulfill that commitment, e.g. due to a generator forced outage. Thus, implementation of real-time co-optimization would provide benefits across the market."

Implementation of the ORDC applied a system-wide perspective on the need for operating capacity (ERCOT Staff & Hogan, 2013). The value of operating reserves arises from the ability to respond quickly to make up for unexpected changes in demand or the availability of capacity. The reserves provide reliable support to balance load over a relatively short period, which could be longer than a single dispatch interval, but would not need to be sustained over a time frame longer than needed to rearrange the normal economic dispatch.

This timing is important in the market design. The standard formulation of the economic dispatch problem assumes an equilibrium condition with system-wide balance and meshed system power flows that are subject to transmission constraints over longer durations, including steady-state conditions. These transmission constraints give rise to power congestion problems and the associated congestion costs that create locational differences in efficient energy prices. The transmission constraints can have different limits for different durations, but the essence is that the transmission constraints interact with the flows in the interconnected grid and give rise to the locational congestion costs.

For a system-wide ORDC, as in ERCOT, an assumption is that any actual dispatch from the reserves would be over such a short interval that the longer duration dispatch transmission constraints would not apply. In other words, the possible use of the generation reserves would not be limited by the normal transmission constraints. Therefore, generation at any location could provide operating reserves on the same basis as any other location. Hence, there would be no congestion costs for reserves and no locational price for operating reserve capacity scarcity.

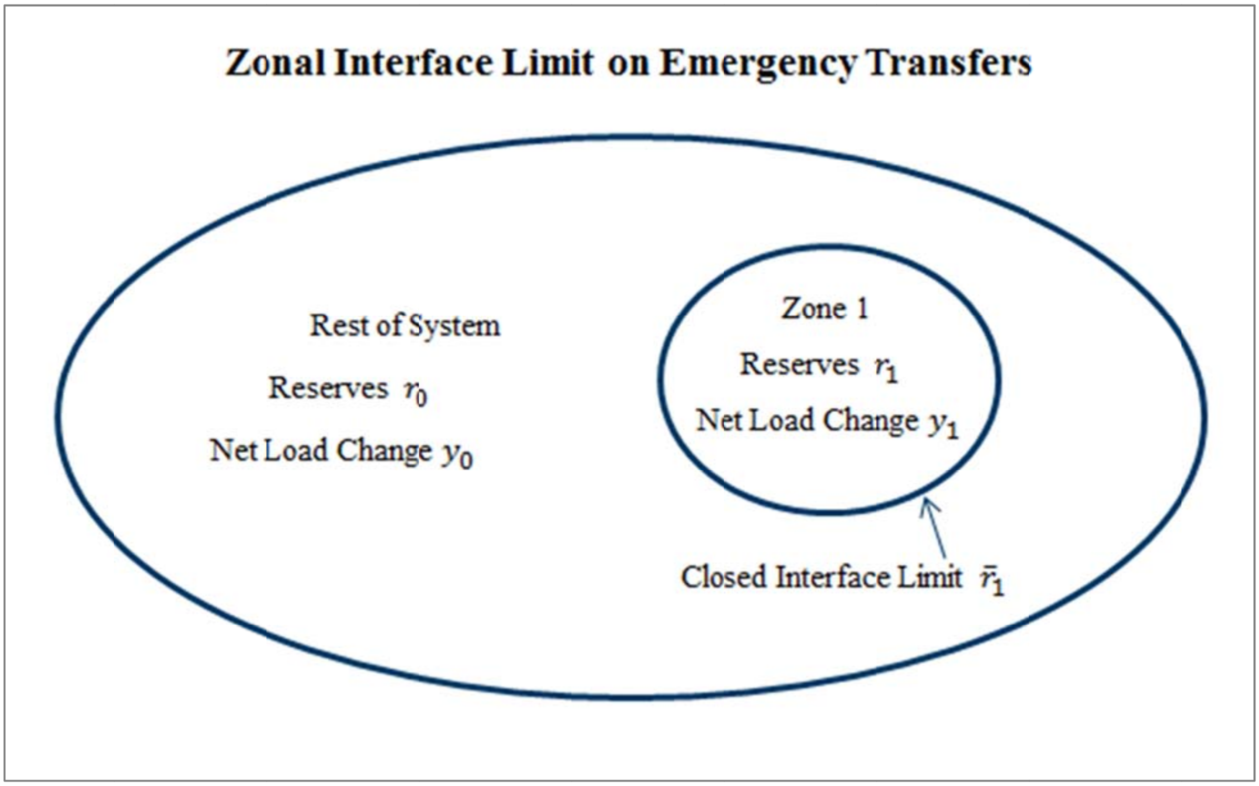
The simplifying assumption of no local reserve constraints for the ORDC in the original design could be revisited. Electricity systems can give rise to locational reliability concerns where generation and operating reserves have different locational effects over the interval covered in response to unexpected changes in load or generation. Under these circumstances the local reliability requirements would translate into different reserve requirements and different locational prices. Hence, in other systems such as MISO, NYISO, PJM, and ISO-NE, there are locational operating reserve requirements, in addition to the aggregate requirements for the system as a whole.[83]

The locational reserve constraints are not as complex as the full equilibrium power flow limits in meshed systems. But locational constraints can create differences in locational power prices. A common model of the underlying power flows governing the operating reserve requirement is to assume that there is a local region ("operating reserve zone"), as conceptually illustrated in Figure 17. Within the zone there are now two sources of operating reserves. Some of the

[83] For example, see NYISO Ancillary Service Manual, Version 4.8 December 13, 2016, pp. 6-22-6-24.

reserves can be provided from locations outside the zone, but the amount that can be provided from outside is limited by a closed interface that defines the maximum flow of power into the local zone. The balance of the operating reserves would be provided by sources within the zone.

Figure 17



The closed interface between the zone and the rest of the system creates an interaction between the steady-state dispatch of power and the possible emergency power flow dealing with the dispatch of the operating reserves. The more power flowing into the zone in the regular dispatch, the less capability there is to rely on the rest of the system for operating reserves. This interaction creates a locational scarcity condition, and therefore a locational price differential, that would appear both in the price for reserves and in the locational price for power.

This locational model for operating reserves then has three components: an ORDC for the constrained zone, a closed interface limit for power flows into the zone, and an ORDC for the balance of the system. With one such local operating zone, there would now be three interacting components, each with its own scarcity price. The principles are the same as for the single regional ORDC, but the details allow for a model of the interaction of these prices (Hogan, 2010). Furthermore, the same principles apply to having multiple operating reserve zones, each with its own reserve demand and interface constraint. The key incremental requirement beyond system-wide ORDC would be to identify the locations comprising each constrained zone and to perform calculations to estimate the size of the zonal interface constraint.[84] The Appendix includes a further discussion of the modeling approach, including an example of how to construct the interacting ORDC components and include them in the co-optimization with the energy dispatch.

Figure 18

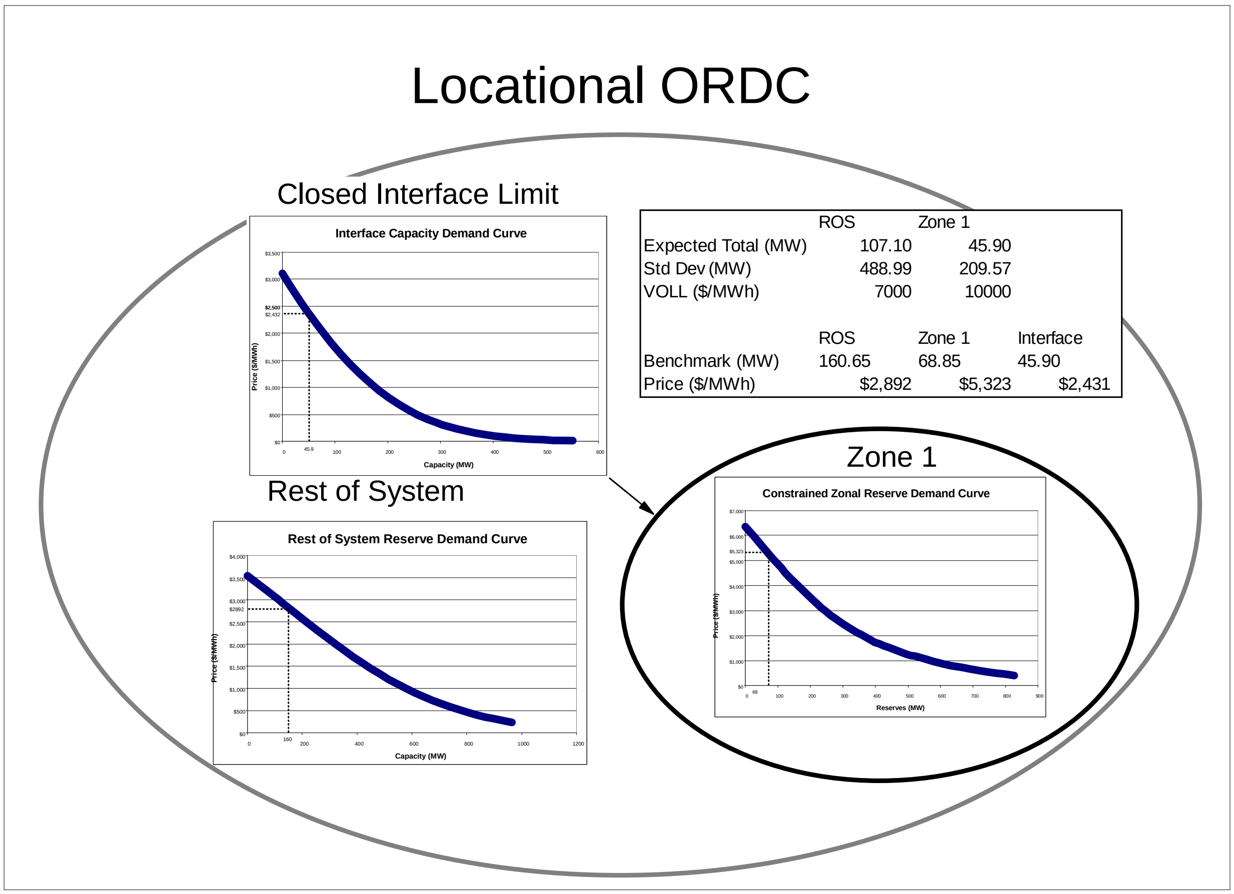


Figure 18 provides an example of the scarcity calculations for a locational ORDC. In the example, there are separate reserve demand curves for Zone 1 and for the Rest of the System because because a closed interface limit constrains the import of reserves to Zone 1 from the Rest of the System. For simplicity, we set the "X" values at zero. The available interface capacity is 45.9 MW, meaning that at most 45.9 MW of reserves scheduled in the Rest of the System are available for use in Zone 1. Inside Zone 1, the ORDC incorporates a probability distribution for the change in net load, which in the illustration has a mean of 45.9 and a

[84] See the Capacity Emergency Transfer Limit (CETL) in PJM Manual 14B, Revision 36, November 17, 2016, pp. 63-68.

standard deviation of 209 MW, and the VOLL for Zone 1, which is assumed to be $10,000/MWh. Outside the constrained zone, for the Rest of the System, the mean and standard deviation of net-load change are 107 and 489 MW, respectively, and the assumed VOLL is $7,000/MWh. In the co-optimized security constrained dispatch given the bids and offers for energy and reserves inside and outside of Zone 1, there are 161 MW of reserves scheduled outside of the constrained zone, and 68 MW of reserves scheduled inside of the constrained zone, and the import of reserves into Zone 1 is at the interface capacity limit of 45.9 MW. The co-optimized dispatch including both regional and local ORDC curves and the associated definitions of closed interface limits defining local reserve zones, as described in the Appendix, produces scarcity prices of $2,892/MWh outside the constrained zone, $5,323/MWh inside the constrained zone, and $2,432/MWh for the incremental transfer capacity. These prices correspond to schedules of 160.65 MW of reserves in the Rest of the System, and 68.85 in Zone 1.

Application of a locational operating reserve requirement in ERCOT arises as an important market feature whenever there is a material locational reliability requirement. For example, existence of an RMR unit at a particular location must arise because of a locational reliability requirement. Similarly, local market power mitigation through offer caps suggests a locational reliability requirement that could accompany such mitigation and provide the necessary locational scarcity pricing through the local ORDC.

By improving price formation during periods of local scarcity, locational scarcity pricing would help to reduce the frequency of out-of-market interventions to maintain reliability, such as RUC commitments. Increased locational prices provide a market incentive for units to be available, where and when needed, to respond based on their offers to ERCOT dispatch instructions. Additionally, improved real-time scarcity pricing will likely increase the incentive for resources to participate in the day-ahead market, relative to the situation today where units committed in the day-ahead market consistently face the possibility of receiving a make-whole payment and earning no margin above their costs. The alternative of self-commitment is even worse, as a self-committed unit does not receive the guarantee of a make-whole payment in the event that energy prices are lower than expected or turn negative. Because of the low prices today, there is an incentive for the owners of some units to elect not to offer into the day-ahead market and, instead, decide whether or not to self-commit subsequent to receiving a RUC instruction. This optionality, which is allowed by the market rules, is a rational response to low prices and could be a reason for the increased frequency of RUCs during the current period of low energy prices.

Locational Scarcity Pricing with Transmission Constraint Penalty Functions

In addition to improvements to price formation, ERCOT should consider changes to its rules and software for commitment and dispatch to reduce the commitment of RUC units and other out-of-market reliability actions, and thereby avoid inefficient price suppression and the dampening of market incentives. As mentioned above, ERCOT recently decreased the penalty factors (i.e. shadow price caps) modeled in the RUC engine, but they are still static and relatively high.[85]

An additional change to be considered in the near term would be to modify SCED transmission constraint penalty values to enable brief excursions of transmission flows into emergency levels during normal operation in order to avoid the higher cost of an additional unit commitment. This type of software change should be relatively straightforward. These default penalty factors could be modified to levels more reflective of the estimated cost of the probability of lost load if the constraint is violated. Going further, the transmission constraint could be represented as a penalty curve function, where the cost of the violation is an increasing function of the magnitude or duration of the excursion.[86]

[85] ERCOT, "W-A040617-01 Changes to transmission constraint Shadow Price caps," Operations Notice to ERCOT Market Participants, April 6, 2017. See MISO transmission demand curve values at https://www.misoenergy.org/_layouts/MISO/ECM/Download.aspx?ID=168921

[86] MISO transmission demand curves (i.e., penalty functions) depend on the voltage level of the transmission element and the percentage violation. *Ibid.*

Socialized Transmission Planning and Cost Recovery Issues

Like the renewable energy policies discussed in a prior section, transmission planning and cost-recovery policies affect the ERCOT energy-only market, but are implemented through regulatory and legislative processes external to the energy market design. Importantly, this second set of policies is internal to Texas, so potentially more amenable to modification to improve consistency with the market-driven philosophy of ERCOT's electricity spot market design. Like renewable energy policies, ERCOT's policies for transmission planning and cost recovery entail subsidization of investments or allocations of fixed costs that directly affect the balance of supply and demand in the energy-only market. In essence, the supply functions and demand functions determining energy-only prices are shifting because of these out-of-market decisions and cost allocations, rather than because of the decisions of energy market participants acting in response to the energy-only market prices.

Following a review of transmission planning and transmission cost recovery in ERCOT, this section describes the following priorities for improvement:

- **Transmission Planning:** Market-reflective policies for transmission investment should be considered as a replacement for Texas' socialized transmission planning, which, by building new transmission in advance of scarcity developing, fails to provide the opportunity for markets to respond.
- **Transmission Cost Recovery:** Alternatives for transmission cost recovery to replace or reduce dependence on the summer peak demand-based mechanism for the allocation of sunk transmission costs would reduce distortion of energy market pricing.

TRANSMISSION PLANNING PROCESS INCONSISTENT WITH ENERGY MARKET OBJECTIVES

Assessment of transmission planning protocols in the U.S. reveals a heavy emphasis on setting transmission system investment to ensure systems meet reliability requirements. These analyses typically look forward five to ten years and analyze the high voltage transmission system that will be needed in the future to meet reliability standards. Because transmission infrastructure additions commonly require lengthy development timelines that often can reach ten years or more, the result of these assessments has been significant investment in transmission infrastructure in some parts of the U.S. to accommodate demand growth and new generation additions. At the same time, there is consideration of transmission system investment that can reduce congestion and/or facilitate the accommodation of policy driven resource additions like renewables. Because the majority of the transmission system investments identified through these planning processes are funded through non-bypassable tariffs, there is little opportunity for competitive generation additions that may directly compete with transmission system infrastructure additions.[87]

The implementation of ERCOT's transmission planning process institutionalizes a preference for identifying transmission system solutions to expected reliability problems and accommodating Texas public policy objectives (such as the CREZ transmission system additions). ERCOT's annual regional transmission planning process results in the regular addition of high voltage ("bulk") transmission system infrastructure to address potential electric system reliability violations and system congestion. The ERCOT Planning Guide outlines the regional planning process undertaken by ERCOT each year to develop a Regional Transmission Plan (RTP)[88] in association with the Regional Planning Group and Transmission Service Providers.[89] The RTP "addresses regional and ERCOT-wide reliability and economic transmission needs and the planned improvements to meet those needs for the upcoming six years starting with the [Steady State Working Group] SSWG base cases."[90]

Under PUCT rules, ERCOT's role is to conduct transmission planning assessments focused on ensuring reliability and minimizing congestion.[91] The RTP process does not explicitly investigate the trade-off between resolving future problems using generation resources as opposed to transmission resources. In particular, when specifying the modeling inputs to the RTP, ERCOT limits the addition of proposed generation in its planning models to those generation resources that have practically already committed to construction.[92] Because generation resources that are permitted and have made financial commitments are usually within a couple years of commencing actual operations, the RTP analysis forward-looking time horizon of six years

[87] As transmission planning has evolved in the U.S. in response to FERC requirements to plan regionally and accommodate transmission proposals driven by public policy requirements there are often opportunities for merchant transmission developers to pursue projects that will qualify for cost-of-service ratemaking. However, there are few examples of merchant transmission development beyond multi-purpose DC lines that interconnect different electric systems providing the opportunity to arbitrage energy and capacity price differences between regions.

[88] ERCOT Planning Guide, Section 3: Regional Planning, January 1, 2017, available at: http://www.ercot.com/mktrules/guides/planning/current. ERCOT bulk transmission system planning is conducted in compliance with the Public Utility Commission of Texas, Chapter 25, Substantive Rules Applicable to Electric Service Providers, §25.361(d), Electric Reliability Council of Texas (ERCOT), http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.361/25.361.pdf.

[89] ERCOT also develops biannually a Long-Term System Assessment which seeks to determine if there may be a more cost-effective system upgrade than may be identified when only examining 6 years forward under the RTP.

[90] ERCOT Planning Guide, Section 3.

[91] See, for example, ERCOT Transmission Planning Assessments, Assessing near-term transmission system needs, December 2016, available at: http://www.ercot.com/content/wcm/lists/114740/CNRTP-Dec2016-FINAL.pdf

[92] ERCOT Planning Guide, Section 6: Data/Modeling, January 1, 2017, at 6.9, available at: http://www.ercot.com/mktrules/guides/planning/current. ERCOT requires that a proposed generation resource have in hand key environmental permits as appropriate and demonstrate a commitment to finance and commence construction of electric interconnection facilities.

ignores generation resources that could be available in years three to six of the forward-looking RTP analysis. Absent explicit consideration of generation and market-based resources as an alternative to transmission resources, the RTP process will virtually guarantee that transmission system investments will preempt and prevent market solutions from resolving expected future problems.

Ironically, ERCOT recently used an RMR agreement to maintain system reliability in a region that would otherwise be supply constrained in the absence of the RMR agreement. The imposition of an RMR agreement allowed time to develop a transmission system upgrade that could be readily implemented, as opposed to accommodating an evaluation of the economic trade-off between generation and transmission solutions that might eliminate the need for the RMR agreement.[93] At the 2016 ERCOT Board of Directors Meeting, Independent Market Monitor David Patton described the damage Texas's transmission planning process, as implemented by ERCOT, inflicts on the energy-only market: "So you're going to be talking in a minute about an RMR contract in Houston, and that should concern you…You can either just keep building transmission and building transmission to make sure you never have areas like that, but in the case of Houston now you have an RMR contract with a generator that's premised I think largely on this sort of need, and the reality is that transmission is not always the cheapest answer. In fact, it's often not the cheapest answer."[94] In contrast, in some regions of the U.S. generation resources are evaluated as potential solutions to system reliability problems in explicit recognition of the impact of new transmission on investment and returns in electricity markets. As discussed previously, the NYISO's reliability planning process provides for consideration of different proposals to resolve a projected reliability issue.[95]

The implication is that the ERCOT transmission planning process preempts generation investment in response to the energy-only market price signal, undermining a key feature of the energy-only market design. Planning and building new transmission based on a six year look-ahead effectively excludes non-transmission solutions (generation and other possible actions that may resolve a reliability problem) that might be implemented more quickly, and at lower cost to consumers, to address reliability issues in the future. By identifying and implementing transmission solutions over a six year period, ERCOT's planning process

[93] See, for example, Public Utility Commission of Texas, Project No. 46369, Rulemaking Related to Reliability Must-Run Service, "Texas Industrial Energy Consumers' Reply Comments on Commission Staff's Strawman"," pp. 8-10 arguing transmission additions are the only possible response that ERCOT can facilitate to alleviate a localized reliability issue.

[94] Patton, David, Potomac Economics, June 14 2016 ERCOT Board of Directors Meeting.

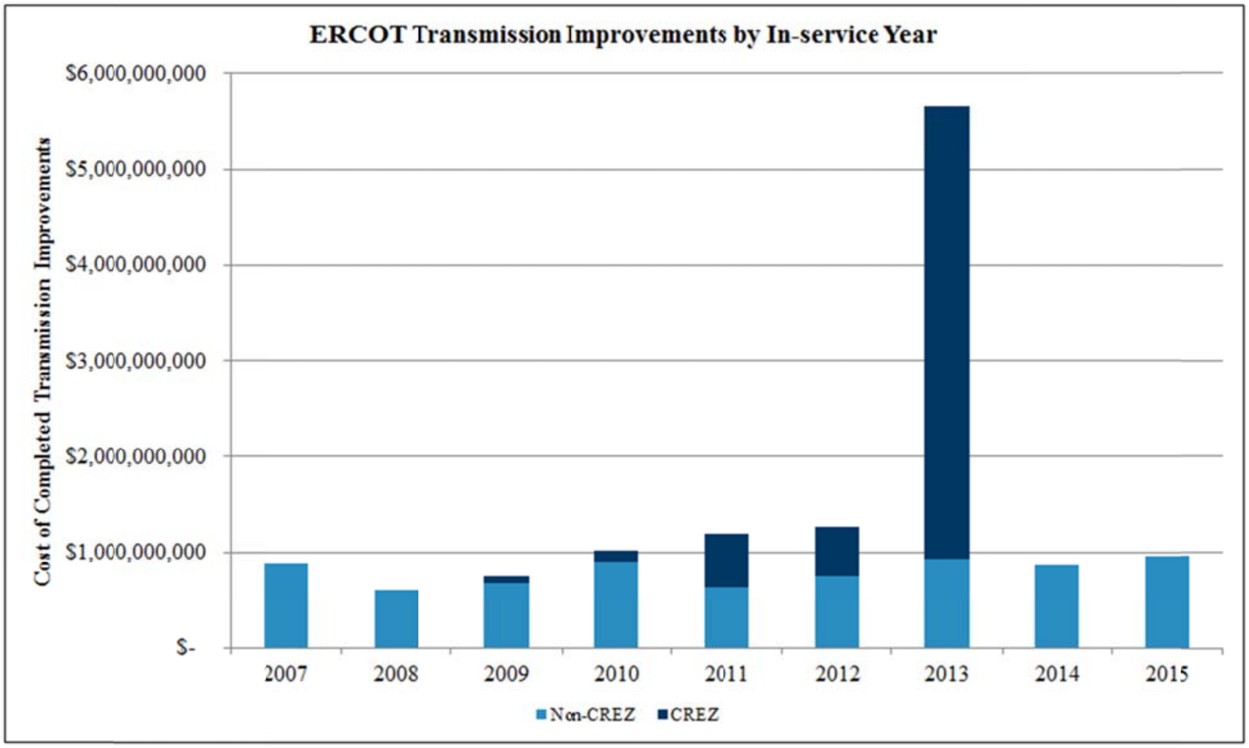
[95] NYISO, "Reliability Planning Process Manual," April 2016, Version 2.3 at Section 5. Available at: http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/rpp_mnl.pdf.

suppresses locational price signals before they occur, preventing more efficient non-transmission solutions to system congestion or reliability issues. Unlike the original intent of electricity market reform in ERCOT, which was to move some or all of the cost risk for system reliability away from load, the effect of transmission planning under the current rules is to substitute regulated infrastructure payments by load for market-based investments in transmission alternatives. Recalling the process of deregulation in Texas through SB-7, the incongruity of this outcome appears in statements at the time: "[T]he law also has shifted the burden of risk for building new power plants to investors from consumers."[96]

ERCOT's transmission planning process is inconsistent with the energy-only pricing paradigm. The challenges faced by privately-funded generation investors when confronting centrally planned transmission, for which the costs are socialized through non-bypassable charges rather than borne by the beneficiaries, has been well recognized. Notably, this discourse has occurred in regions that include a capacity market to support, annually, the continued operation of generation required for reliability. In ERCOT, operating without a capacity market, there is no back-up mechanism to supplement the impact of new transmission on the energy-only revenue of existing generation that may be required for reliability. The transmission planning process suppresses the market price signal that is supposed to be the incentive for generators to respond and build when and where needed in ERCOT.

[96] *Houston Chronicle*, "Many call energy deregulation in Texas a failure," quoting Senator Sibley, October 6, 2007, available at: http://www.chron.com/business/article/Many-call-energy-deregulation-in-Texas-a-failure-1824046.php.

Figure 19[97]

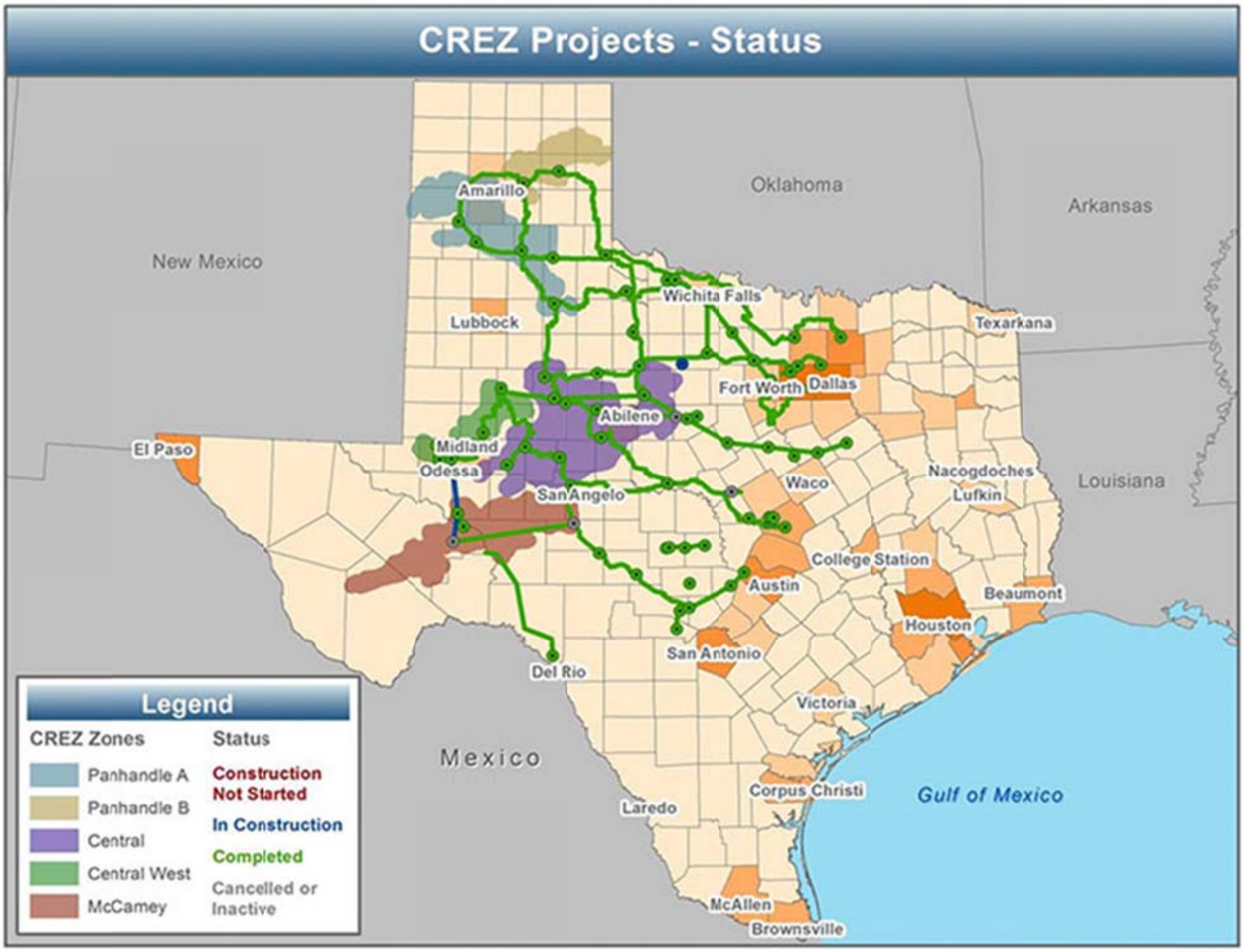


As a case in point, the transmission planning process in ERCOT resulted in the energization of the multi-billion dollar CREZ projects (see Figure 19) to increase transmission capacity from western Texas to the eastern load centers (see Figure 20). The project notably reduced observations of negative prices in ERCOT's western region, where the majority of wind resources have located. At the same time, it increased the incidence of low prices in the Houston area of ERCOT, as shown in Figure 6.

The effect, therefore, was to signal an increase in the value of additional generation in the west, and a decrease in the value of additional generation located in and around Houston. There is an outstanding question of whether the benefits from this large investment exceeds its cost and an even larger question of whether the consequent changes in energy price signals align with the locations where future generation investment is needed for reliability.

[97] ERCOT, "2016 ERCOT Report on Existing and Potential Electric Constraints and Needs"," December 30, 2016, p. 4.

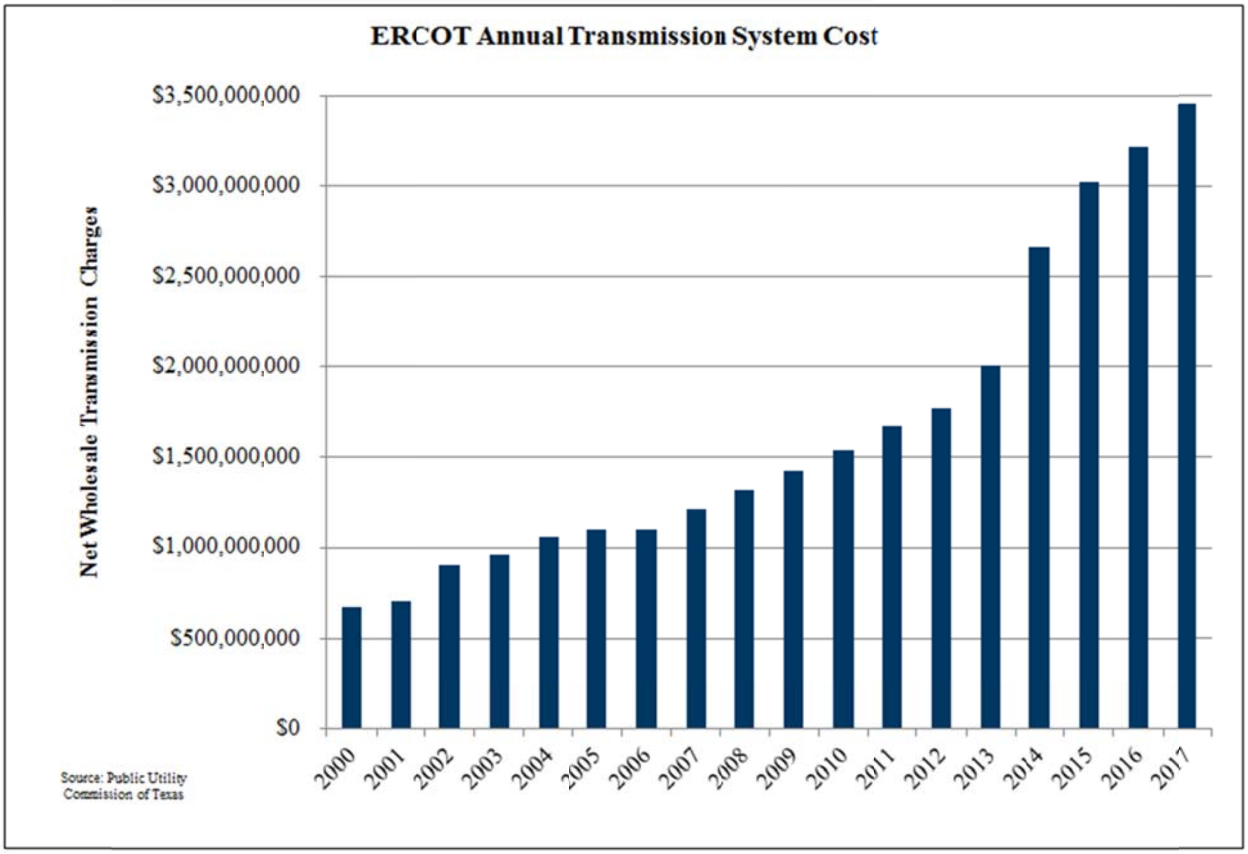
Figure 20


CREZ Projects - Status
Oklahoma
Arkansas
New Mexico
Amarillo
Lubbock
Wichita Falls
Texarkana
Fort Worth
Dallas
Abilene
El Paso
Midland
Odessa
San Angelo
Waco
Nacogdoches
Lufkin
Louisiana
College Station
Austin
Beaumont
Houston
San Antonio
Del Rio
Victoria
Mexico
Laredo
Corpus Christi
Gulf of Mexico
McAllen
Brownsville
Legend
CREZ Zones
Panhandle A
Panhandle B
Central
Central West
McCamey
Status
Construction Not Started
In Construction
Completed
Cancelled or Inactive

FOUR COINCIDENT PEAK (4CP) COST ALLOCATION DISTORTS PEAK PERIOD LOAD

Transmission system investment in Texas exceeded ten billion dollars over the past five years with Texas' CREZ transmission system investment alone exceeding $7 billion.[98] The combination of CREZ and non-CREZ transmission infrastructure development is driving a pronounced increase in ERCOT's annual transmission cost-of-service, as shown in Figure 21.[99]

Figure 21



These substantial increases in the transmission cost-of-service are ultimately passed through to consumers. For example, increases to the transmission components of Oncor's retail delivery

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[98] ERCOT, "2016 ERCOT Report on Existing and Potential Electric Constraints and Needs" December 30, 2016, p. 4.

[99] In ERCOT Transmission Service Providers (TSPs) charge Distribution Service Providers (DSPs) for transmission service based on each DSP's percentage of 4CP for the prior year. DSPs include investor owned utilities, municipal utilities and cooperative utilities. DSPs pass through transmission system costs pursuant to their retail tariff. In competitive service areas the transmission and distribution system costs are charged to Retail Electric Providers who may bill retail customers.

tariff for distribution system customers have ranged from 72% to 147%, depending on customer class, for the period March 2012 to March 2017.[100]

Transmission costs are sunk because, unlike variable costs, they do not change depending on energy demand in an interval. A general principle of market design is to allocate sunk costs to minimize impacts on real-time markets, since allocating sunk costs based on real-time supply or demand can impact the efficiency of the real-time market. ERCOT does not conform to this principle; rather, the transmission costs charged to the largest customers are determined based on their demand in four peak summer intervals using the Four Coincident Peak (4CP) transmission cost allocation methodology.[101] At the end of each year, the PUCT determines the proportion of ERCOT system-wide 4CP load attributable to each distribution service provider.[102] A distribution service provider's load during the interval in which the system-wide peak occurs for each of the months from June to September defines its share of the 4CP and its corresponding allocation of the yearly ERCOT transmission cost-of-service. Distribution service providers recover their annual allocation of transmission service costs through the delivery service tariffs charged to their different classes of customers. Typically, residential and small commercial customers' delivery service tariffs have an energy based (per-kWh) charge, while large commercial and industrial customer delivery service tariffs have a demand-based (per-kW) charge. The demand charge to large commercial and industrial customers with interval meters is applied to the customer's kW load during the identified 4CP intervals.[103] ERCOT reports that the customers who are billed based on their demand during the 4CP intervals represent 44% of the electric load served by ERCOT.[104]

Inevitably, the 4CP transmission cost allocation rule operates as an outside-the-market effect that suppresses peak and near-peak energy scarcity prices. The pronounced increase in the transmission cost-of-service shown in Figure 21, combined with the structure of the 4CP charge, creates a powerful incentive for customers to take actions to reduce their portion of the

[100] Oncor Electric Delivery Company LLC, "Tariff for Retail Delivery Service," 6.1.1 Delivery System Charges, Applicable: Entire Certified Service Area, Effective Date: March 1, 2017, Sheet 6.1, Page 3 of 4, Revision: Thirty-Two. Note that for transmission system customers (not taking service at distribution voltage levels) the rate has increased 58% over the same time period.

[101] There is an inconsistency between determining planning for new transmission needs based on non-coincident peak loads (Steady State Working Group base case) and allocating the costs of these upgrades based on coincident peak load.

[102] See, for example, Texas Public Utility Commission of Texas, Docket No. 45382, Commission Staff's Application to Set 2016 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas, Electric Reliability Council of Texas, Inc.'s Report on the 2015 "4CP" Coincident Peak Load in the ERCOT Region, December 1, 2015.

[103] For example Oncor customer's greater than 10kW are charged the 4CP rate provided that they have an Interval Demand Recorder (IDR) which records customer demand every fifteen minutes. http://www.ercot.com/content/wcm/key_documents_lists/41536/Joint_TDSP_s_4CP_Tariff_Language.docx.

[104] ERCOT, "4CP Overview", February 16, 2017, p. 1; percentage is based on ERCOT load on August. 3, 2011.

transmission cost-of-service. Customers on a 4CP tariff have their monthly transmission charge for the current year calculated based on their prior year's observed 4CP demand. Thus, a customer served under a 4CP tariff that can reduce its load during the actual ERCOT summer monthly system peaks will realize substantial savings on its transmission charges in the following year.

For example, assume an industrial customer has a peak demand of 10 MW and is capable of interrupting its entire demand during each ERCOT peak demand interval during the months of June, July, August, and September.[105] Next, assume that this customer is in the Oncor service territory and served with primary transmission service such that it faces a transmission charge of $4.13 per 4CP kW-month. If the customer were to reduce its 4CP demand to zero, the customer would pay no transmission charge the following year. However, if the customer did not reduce its demand it would be charged 10,000 kW (10 MW) * $4.13/4CP kW, or $41,300/month, which totals $495,600 for the year.

It makes sense for large customers and municipal and cooperative utilities subject to 4CP transmission charges to acquire analytical tools to forecast peak demand periods. Recent ERCOT analyses confirm that as the transmission cost-of-service has increased, customers have been demonstrating increased peak demand reduction coincident with ERCOT's peak periods. For example, ERCOT has recently estimated a pronounced increase in the magnitude of municipal and cooperative utilities' peak demand reduction over the past several years during which transmission costs have increased.[106] Increased transmission costs, combined with the design of the 4CP charge, are reducing peak demand and putting downward pressure on ERCOT energy market prices during peak demand periods.

The 4CP transmission charge raises an issue for energy-only markets because the reduction in demand during peak periods is not occurring in response to energy prices, but instead is in response to avoiding an allocation of sunk transmission costs. The incremental cost faced by 4CP customers for additional power consumption during potential peak intervals is not equal to the energy price paid to energy suppliers at the same location at the same time. During a potential 4CP interval, a 4CP customer faces an incremental cost for an additional MW of consumption equal to (approximately) ¼ of the 4CP transmission charge (since the customer's peak demand is averaged over four intervals), plus the locational price of energy.[107] This price for incremental consumption for 4CP customers during potential peak demand intervals is

[105] This example is based on the now out-of-date example provided by ERCOT in its 4CP Overview, February 16, 2017, p. 4.

[106] Raish, Carl L, Principal Load Profiling and Modeling, ERCOT Demand Side Working Group, "Analysis of NOIE Load Reductions Associated with 4-CP Transmission Charges/Price Response in ERCOT," June 17, 2016, at 12. http://www.ercot.com/content/wcm/key_documents_lists/27290/Demand_Response_Presentations.zip

[107] There also is a feedback effect whereby a reduction in the 4CP load of all customers will increase the 4CP rate.

orders of magnitude higher than the energy price paid to suppliers, creating an inconsistency from the perspective of efficient energy-only market design. The 4CP mechanism leads to inefficient load reductions because the marginal cost of electricity supply will be lower than the opportunity cost of load reductions.

With the 4CP transmission cost allocation, 44% of ERCOT load has an enormous out-of-market incentive to reduce demand during exactly the peak intervals when prices would otherwise be high or rising in an energy-only market. In effect, there is a payment, in terms of avoided transmission and distribution charge allocations in the following year, leading to a reduction in peak demand and in energy prices. Importantly, there is no real reduction in transmission or distribution costs. This is clearly demonstrated in Figure 21. The charges are just allocations of sunk costs. Hence, real costs are incurred to reallocate sunk costs among market participants.

ERCOT has recently estimated the 4CP response during peak load hours of as high as 1,408 MW.[108] Assuming this reduction were to occur at a time when the ORDC would otherwise be included in the locational price; prices throughout ERCOT could be reduced by hundreds of dollars per MWh.

Demand reductions resulting from the 4CP transmission cost-recovery mechanism are not in response to high system marginal costs, but instead are in response to the allocation of sunk costs. On a net basis, there are no cost savings, only a reallocation of the costs to other customers. In principle, the most perverse outcome would be to have everyone shifting costs onto everyone else, so that on balance no customer avoids the transmission payment but every customer incurs real expenses in the attempt.

IMPROVEMENTS TO TRANSMISSION PLANNING AND COST RECOVERY TO SUPPORT ENERGY-ONLY MARKET

An alternative approach to the PUCT and ERCOT's current transmission planning and cost allocation rules would be to modify the transmission planning, expansion and cost allocation protocols to focus on a beneficiaries-pay system. Such a system would enable and encourage explicit consideration of all competing investments, including generation and storage, that are substitutes for transmission in meeting system-wide or local reliability objectives during future time periods. As mentioned, the NYISO pro forma process could serve as a model for ERCOT.

The PUCT should be wary of the impact 4CP has on energy price formation. The Commission could evaluate and ultimately adopt an alternate transmission cost allocation methodology that is congruent with the energy-only market. For example, efficient pricing for transmission cost

[108] Raish Analysis at 10. http://www.ercot.com/content/wcm/key_documents_lists/27290/Demand_Response_Presentations.zip

recovery would follow the general outline of a two-part tariff, with fixed and variable components.

Typically for transmission infrastructure, the variable component ($/kWh) would be insufficient to recover the full cost of the transmission investment. The fixed component would be used to collect the balance of the requirement in a manner that provided the least distortion to peak demand decisions. Although a perfect fixed and variable charge may not be achieved, it should be possible to provide workable access charges that do not distort energy pricing because they depend so directly on individual peak demand decisions.

This situation may not be amenable to full correction in the short term through modification to allocation rules for transmission cost recovery; however, the PUCT should closely examine this issue as the current 4CP transmission cost allocation mechanism is fundamentally in conflict with the energy-only market.

Conclusion

ERCOT employs an open wholesale electricity market as the basis for short-term reliable electricity supply as well as for long-term investments to maintain reliability in the future. Pricing and settlement rules for the real-time energy-only market must provide efficient incentives for market participants to respond to scarcity conditions so as to avoid a situation in which reliability is provided, instead, by expensive non-market interventions, such as RUCs and RMR contracts. The introduction of the system-wide ORDC to provide for region-wide scarcity pricing was a major step in the evolution of the market.

Lower natural gas prices and the proliferation of renewables in ERCOT have changed market fundamentals and transformed the balance sheets of electricity generation owners in the region. These changes in broader economic trends and national policies cannot be reversed, nor is it the purpose of good market design to attempt to reverse or unwind what is already done. But the low level of region-wide energy prices and ORDC adders are sending a message for dispatchable resources to exit the market or delay maintenance expenditures, and elevate the importance of improving price formation to ensure that it is fundamentals, and not avoidable market influences or defects that drive the process of decisions about retirement, entry or plant maintenance.

A review of energy price formation in ERCOT leads to two important conclusions: (i) while the ORDC is performing consistently within its design, scarcity price formation is being adversely influenced by factors not contemplated by the ORDC; (ii) other aspects of the ERCOT market design must be improved to better maintain private market response to energy prices as the driver of resource investment, maintenance expenditure and retirement decisions.

The following policy and price formation improvements are recommended to ensure a sustainable structure consistent with tenets of energy-only market design.

System-wide Price Formation

- **Marginal Losses:** ERCOT should include the marginal cost of losses in its energy market dispatch and pricing. The current omission of marginal losses creates a persistent inefficiency in locational prices and an elevation of the real cost of serving load that can accumulate to have an effect of the same order of magnitude as the effect of marginal congestion.
- **ORDC Enhancements:** ERCOT's system-wide ORDC calculation should be enhanced to address the reliability impacts of changes in the generation supply mix, through a conservative shift in the LOLP, and the price impacts of reliability deployments, by subtracting such capacity from the measure of available reserves.

Locational Scarcity Pricing

- **Out-of-Market Actions to Manage Transmission Constraints:** Reliability constraints can create perverse conditions when they induce out-of-market actions that, in combination with market power mitigation, result in lower, not higher, market prices. Local scarcity pricing and mitigation rules require changes to properly set prices when there are reliability unit commitments or other ERCOT reliability actions to manage transmission constraints; these changes should not disable rules for local market power mitigation.
- **Dispatch and Pricing for Local Reserve Scarcity:** A second step to price local scarcity and avoid out-of-market actions would be the introduction of local reserve requirements, implemented through co-optimization of the energy dispatch and reserve schedules, to properly set prices when there are constraints on reserve availability in a sub-region.

Transmission Planning and Cost Recovery

- **Transmission Planning:** Currently, out-of-market transmission planning occurs ahead of the development of scarcity and diminishes the scarcity price signals that would lead, in the alternative, to market-based investment. Market-reflective policies for transmission investment should be considered as a replacement for Texas' socialized transmission planning, which fails to provide the opportunity for markets to respond.
- **Transmission Cost Recovery:** The allocation of transmission charges based on peak period usage (4CP) leads to price suppression as well as welfare loss as market loads make expensive decisions to avoid allocations of sunk costs that cannot be avoided in the aggregate. Alternatives for transmission cost recovery to replace or reduce dependence on the summer peak demand-based mechanism for the allocation of sunk transmission costs would reduce distortion of energy market pricing.

Appendix: Formulation and Computation of Local Reserve Scarcity Prices through Operating Reserve Demand Curves

A representation of the value of operating reserves is essential for establishing prices for energy and reserves. This Appendix provides further detail on the structure of the operating reserve demand curve as now applied in ERCOT and discusses possible extensions. The ORDC provides an approximation of the value of operating reserves appropriate for inclusion in a single period representation of a dispatch model. The current ERCOT application treats pricing as arising essentially as if it were within a co-optimization framework, although full dispatch co-optimization of reserves and energy is not yet in place.

The full co-optimization framework, simultaneously considering both the dispatch of energy and reserves to meet forecast load conditions, could be important for some extensions of the ORDC. In this framework, the offer costs and value of reserves (where the latter is measured by the ORDC) trade off against the offer costs and locational demands for energy in the simultaneous dispatch. The co-optimization model extends the use of the current ORDC.

The existing ERCOT ORDC has one assumed emergency response, which requires involuntary curtailment of load priced at the Value of Lost Load (VOLL). This action is triggered at the associated minimum contingency level of reserve requirement. Furthermore, the existing ORDC is for a system-wide requirement under the assumption that using the reserves over a short interval would not confront any transmission constraints.

The first extension discussed below would be to unpack the emergency response to better track the actual practice during emergency conditions. In particular, ERCOT has a number of Energy Emergency Alert stages that precipitate emergency actions of increasing severity. These different actions would have costs lower than VOLL, but the reserve levels where they would be applied would be higher than the contingency minimum. For simplicity, the existing ERCOT design makes the compromise of having a trigger level (the "X" factor) that is higher than the true minimum contingency reserve level but lower than the initiation of the Energy Emergency Alerts. Extending the ORDC to better approximate the various Energy Emergency Alerts would be possible. This would require estimating the trigger levels, which is complicated by the variance between Physical Responsive Capability, which triggers Energy Emergency Alerts) and ORDC reserves (which triggers ORDC price adders), and estimating the avoided cost values of the emergency actions, which could also prove difficult. An example of a model for a multi-step ORDC representation in the dispatch model is described and illustrated below.

A second extension would be to address the situations in which transmission constraints would be relevant in the event of deployment of operating reserves. This condition would create a locational requirement for operating reserves. Moreover, because the requirements would lead to separation in the prices and value for reserves in different locations, the transmission limits would imply locationally differentiated operating reserve products. A locational requirement would be paired with the identification of the locations of each constrained zone. Associated with each zone, the approach would require estimates of the probability of net load changes for a given time step (hourly), analogously to the estimation of the probabilities for the current ERCOT-wide ORDC. In addition, the analysis would require an estimate of the capacity of a closed interface constraint that would restrict the flow of energy and dispatch of reserves into the constrained region. These would be used to construct locational operating reserve demand curve values. The locational supply and demand for reserves and interface capacity would interact with the system wide supply and demand for reserves and this would produce an ORDC function that determines the price for each as a function of the availability of total reserves, local reserves and the interface constraint. The sections below provide a derivation of such a model of a locational ORDC and the necessary changes to incorporate this representation of operating reserves in the dispatch objective function.

The outline of the formulation of system-wide and local ORDCs provides guidance for applying the basic principles in practice. By its nature, an ORDC is an approximation of a complex reality. Some approximation is necessary to make the power dispatch problem tractable. Furthermore, the details will depend on the actual system constraints and operating practices. The following summarizes the major elements of a model that incorporates an explicit treatment of an ORDC and provides a guide for implementation. This Appendix derives from and extends the earlier discussion in prior work (Hogan, 2013).

ECONOMIC DISPATCH AND OPERATING RESERVES

The assumption of the existence of an operating reserve demand curve simplifies the analysis. The demand curve gives rise to a reserve benefit function that can be included in the objective function for economic dispatch. The basic framework approximates the complex problem with a wide range of uncertainties and applies a pricing logic to match the actions of system operators. The main features include:

- **Single Period Model**. There is a static representation of the underlying dynamic problem. This static formulation is a conventional building block for a multi-period framework.
- **Deterministic Representation**. The single period dispatch formulation is based on bids, offers, and expected network conditions as in standard economic dispatch models. The operating reserve demand curve represents the value of uncertain uses of reserves without explicitly representing the uncertainty in the optimization model.

- **Security Constrained**. The economic dispatch model includes the usual formulation of N-1 contingency constraints to preclude cascading failures.
- **Ex-Ante Dispatch**. The dispatch is determined before uncertainty about net load relative to forecast is revealed.
- **Expected Value for Reserves**. The reserve benefit function represents the expected value of avoiding involuntary load curtailments and similar emergency actions.
- **Multiple Reserve Types**. The model of the operating reserve demand allows for a typical cascade model of different reserve types. Online spinning reserves and fast start standby reserves interact to provide complementary reserve prices.
- **Administrative Balancing**. Subsequent uncertain events are treated according to administrative rules to utilize operating reserves to maintain system balance and minimize load curtailments.
- **Consistent Prices**. The model co-optimizes the dispatch of energy and reserves and produces a consistent set of prices for the period.

The framework allows for a variety of implementations with multiple zones, forward markets and other common aspects of electricity markets.

MODELING ECONOMIC DISPATCH AND OPERATING RESERVES IN A CO-OPTIMIZED SYSTEM

The model presented below is a one-period DC-load model with co-optimization of reserves and energy. The notion is that the dispatch set at the beginning of the period must include some operating reserves that could deal with subsequent uncertain events. The emphasis is on the co-optimization of energy and reserves to illustrate the major interactions with energy prices. The initial approach assumes no locational constraints on reserves. The canonical example assumes the existence of a separable non-locational benefit function for reserves.

Here the various variables and functions include:

d: Vector of locational demands

g_R: Vector of locational responsive generation

r_R: Vector of locational responsive reserves

r_{NS}: Vector of locational non-spin reserves

r_R^0: Aggregate responsive reserves

r_{NS}^0: Aggregate non-spin reserves

g_{NR}: Vector of locational generation not providing reserves

$B(d)$: Benefit function for demand

$C_k(g_k)$: Cost function for generation offers

K_k: Generation Capacity

$R_k(r_k)$: Reserve value function integrating demand curves

$r_k^{\max}$: Maximum Ramp Rate

H, b: Transmission Constraint Parameters

i: Vector of ones.

Assuming that unit commitment is determined, the stylized economic dispatch model is:

(1)

$$\begin{array}{lcc}
\underset{d, g_R, g_{NR}, r_R^0, r_R, r_{NS}^0, r_{NS} \ge 0; y}{Max} & B(d) - C_R(g_R) - C_{NR}(g_{NR}) + R_I(r_R^0) + R_{II}(r_{NS}^0) & \\
d - g_R - g_{NR} = y & \text{Net Loads} & \rho \\
i^t y = 0 & \text{Load Balance} & \lambda \\
Hy \le b & \text{Transmission Limits} & \mu \\
g_R + r_R \le K_R & \text{Responsive Capacity} & \theta_R \\
g_{NR} \le K_{NR} & \text{Generation Only Capacity} & \theta_{NR} \\
r_{NS} \le K_{NS} & \text{Non-Spin Capacity} & \theta_{NS} \\
i^t r_R = r_R^0 & \text{Responsive Reserves} & \gamma_R \\
i^t r_R + i^t r_{NS} = r_{NS}^0 & \text{Non-Spin Reserves} & \gamma_{NS} \\
r_R \le r_R^{\max} & \text{Responsive Ramp Limit} & \eta_R \\
r_{NS} \le r_{NS}^{\max} & \text{Non-Spin Ramp Limit} & \eta_{NS}.
\end{array}$$

This formulation assumes that the non-spinning reserve generators are not spinning and, therefore, cannot provide energy for the dispatch. The Non-Spinning Reserve equation implements a cascade model for reserves, where both responsive and non-spinning reserves contribute to the aggregate non-spinning supply.

For the present discussion, the pricing relationships follow from the usual interpretation of a convex economic dispatch model. This could be expanded to include unit commitment and extended LMP formulations (ELMP), but the basic insights would be similar (Gribik et al., 2007).

An interpretation of the prices follows from analysis of the dual variables and the complementarity conditions. For an interior solution, the locational prices (ρ) are equal to the demand prices for load.

(2) $$\rho = \nabla B(d).$$

The same locational prices connect to the system lambda and the cost of congestion for the binding transmission constraints in the usual way.

(3) $$\rho = \lambda i + \mu^t H.$$

In addition, the locational prices equate with the marginal cost of generation plus the cost of scarcity.

(4) $$\rho = \nabla C_R\left(g_R\right) + \theta_R.$$

A similar relation applies for the value of non-reserve related generation.

(5) $$\rho = \nabla C_{NR}\left(g_{NR}\right) + \theta_{NR}.$$

The marginal value of responsive reserves connects to the scarcity costs of capacity and ramping limits.

(6) $$\theta_R + \eta_R = \gamma_R i + \gamma_{NS} i = \frac{dR_I\left(r_R^0\right)}{dr} i + \frac{dR_{II}\left(r_{NS}^0\right)}{dr} i.$$

The corresponding marginal value of non-spinning reserves reflects the scarcity value for capacity and ramping limits.

(7) $$\theta_{NS} + \eta_{NS} = \gamma_{NS} i = \frac{dR_{II}\left(r_{NS}^0\right)}{dr} i.$$

If there are no binding ramp limits for responsive reserves, then $\eta_R = 0$ and from (6) we have θ_R as a vector where every element is the price of responsive reserves. Similarly, for the ramping limits on non-spinning reserves, if these are not binding, then $\eta_{NS} = 0$ and from (7) we have θ_{NS} as a vector where every element is the price of non-spinning reserves.

AN APPROXIMATE OPERATING RESERVE DEMAND CURVE IN A CO-OPTIMIZED SYSTEM

This co-optimization model captures the principal interaction between energy offers and scarcity value. The assumption of a benefit function for reserves simplifies the analysis. Here, a derivation of a possible reserve benefit function provides a background for describing the form of an ORDC. To simplify the presentation, focus on the role of responsive reserves only. And consider only an aggregate requirement for reserves with no locational constraints.

To the various variables and functions add:

$f(x)$: Probability for net load change equal to x

Again, for purposes of designing the ORDC take that unit commitment as given. The stylized economic dispatch model includes an explicit description of the expected value of the use of reserves. For the reserves here, only aggregate load matters. This reserve description allows for a one-dimensional change in aggregate net load, x, and an asymmetric response where positive net load changes are costly and met with reserves and negative changes in net load are ignored. This model is too difficult to implement but it provides an interpretation of a set of assumptions that leads to an approximate ORDC. Here we first ignore minimum reserve requirements to focus on the expected cost of the reserve dispatch.

The central formulation treats net load change x and use of reserve, δ_x, to avoid involuntary curtailment. This produces a benefit minus cost of $VOLL \cdot \left(i^t \delta_x\right) - \left(C_R\left(g_R + \delta_x\right) - C_R\left(g_R\right)\right)$ and this is weighted by the probability $f(x)$. This term enters the objective function summed for all non-negative values of x. The basic formulation includes:

$$\max_{d, g_R, g_{NR}, r_R, \delta_x \geq 0; y} B(d) - C_R(g_R) - C_{NR}(g_{NR}) + \sum_{x \geq 0} \left(VOLL\, i^t \delta_x - \left(C_R\left(g_R + \delta_x\right) - C_R\left(g_R\right)\right)\right) f(x)$$

(8)

$$\begin{array}{lll}
d - g_R - g_{NR} = y & \text{Net Loads} & \rho \\
i^t y = 0 & \text{Load Balance} & \lambda \\
Hy \leq b & \text{Transmission Limits} & \mu \\
g_R + r_R \leq K_R & \text{Responsive Capacity} & \theta_R \\
i^t \delta_x \leq x, \forall x & \text{Responsive Utilization} & \gamma_x \\
\delta_x \leq r_R, \forall x & \text{Responsive Limit} & \varphi_x \\
g_{NR} \leq K_{NR} & \text{Generation Only Capacity} & \theta_{NR}.
\end{array}$$

This model accounts for all the uncertain net load changes weighted by the probability of outcome, and allows for the optimal utilization of reserve dispatch in each instance. This problem could produce scarcity prices that could differ across locations due to the normal transmission constraints on energy.

To approach the assessment of how to approximate reserves with a common scarcity price across the system, further simplify this basic problem.

1. Treat the utilization of reserves as a one-dimensional aggregate variable.
2. Replace the responsive reserve limit vector with a corresponding aggregate constraint on total reserves.
3. Utilize an approximation of the cost function, $\hat{C}$, for the aggregate utilization of reserves, and further approximate the change in costs with the derivative of cost times the utilization of reserves.

This set of assumptions produces a representation for the use of a single aggregate level of reserves for the system:

(9)

$$\begin{array}{lll}
\underset{d,g_R,g_{NR},r_R,\delta_x \geq 0;y}{Max} & B(d) - C_R(g_R) - C_{NR}(g_{NR}) + \sum_{x \geq 0} \left(VOLL\delta_x - \partial\hat{C}_R(i^t g_R)\delta_x \right) f(x) & \\
d - g_R - g_{NR} = y & \text{Net Loads} & \rho \\
i^t y = 0 & \text{Load Balance} & \lambda \\
Hy \leq b & \text{Transmission Limits} & \mu \\
g_R + r_R \leq K_R & \text{Responsive Capacity} & \theta_R \\
\delta_x \leq x, \forall x & \text{Responsive Utilization} & \gamma_x \\
\delta_x \leq i^t r_R, \forall x & \text{Responsive Limit} & \varphi_x \\
0 \leq r_R, & \text{Explicit Sign Constraint} & \omega_R \\
g_{NR} \leq K_{NR} & \text{Generation Only Capacity} & \theta_{NR}.
\end{array}$$

This formulation provides a reasonably transparent interpretation of the implied prices. Focusing on an interior solution for all the variables except r_R, we would have locational prices related to the marginal benefits of load:

(10) $\rho = \nabla B(d).$

The same locational prices connect to the system lambda and the cost of congestion for the binding transmission constraints.

(11) $\rho = \lambda i + H^t \mu.$

The locational prices equate with the marginal cost of generation-only plus the cost of scarcity when this generation is at capacity, which appears in the usual form.

(12) $\rho = \nabla C_{NR}(g_{NR}) + \theta_{NR}.$

The locational prices equate with the marginal cost of responsive generation and display the impact of reserve scarcity. First, the impact of changing the base dispatch of responsive generation implies:

$$\rho = \nabla C_R\left(g_R\right) + \sum_{x \geq 0}\left(\partial^2 \hat{C}_R\left(i^t g_R\right)\delta_x i\right) f\left(x\right) + \theta_R.$$

The second-order term captures the effect of the base dispatch of responsive dispatch on the expected cost of meeting the reserve utilization. This term is likely to be small. For example, if we assume that the derivative $\partial \hat{C}_R$ is constant, then the second order term is zero.

When we account for the base dispatch of reserves, we have:

$$\theta_R = \sum_{x \geq 0} \varphi_x i + \omega_R .$$

When accounting for utilization of the reserves, we have:

$$\gamma_x + \varphi_x = \left(VOLL - \partial \hat{C}_R\left(i^t g_R\right)\right) f\left(x\right).$$

Let $r = i^t r_R$. Then for $x \leq r, \quad \varphi_x = 0; \quad x \geq r, \quad \gamma_x = 0$. Hence,

$$\theta_R = \sum_{x \geq r} \varphi_x i + \omega_R = \left(VOLL - \partial \hat{C}_R\left(i^t g_R\right)\right)\left(1 - F\left(r\right)\right) i + \omega_R .$$

Combining these, we can rewrite the locational price as:

(13) $$\rho = \nabla C_R\left(g_R\right) + \sum_{x \geq 0}\left(\partial^2 \hat{C}_R\left(i^t g_R\right) i \delta_x\right) f\left(x\right) + \left(VOLL - \partial \hat{C}_R\left(i^t g_R\right)\right)\left(1 - F\left(r\right)\right) i + \omega_R.$$

Equations (2) thru (13) capture our approximating model for aggregate responsive reserves. Here $1 - F\left(r\right) = Lolp\left(r\right)$. The term $\left(VOLL - \partial \hat{C}_R\left(i^t g_R\right)\right)\left(1 - F\left(r\right)\right)$ in (13) is the scarcity price of the ORDC. If the second order terms in (13) are dropped, then the scarcity price is the only change from the conventional generation only model. In practice, we would have to update this model to account for minimum reserve levels, non-spin, and so on, to include an estimate of $\bar{c} \approx \partial \hat{C}_R$ in defining the net value of operating reserves $v \approx VOLL - \bar{c}$.

Note that under these assumptions the scarcity price is set according to the opportunity cost using $\hat{C}$ for the marginal responsive generator in the base dispatch. Depending on the accuracy of the estimate in $\hat{C}$, this seeks to maintain that the energy price plus scarcity price never exceeds the value of lost load.

Providing a reasonable estimate for $\hat{C}$ could be done either as an (i) exogenous constant, (ii) through a two-pass procedure, or (iii) approximately in the dispatch. For example, a possible procedure would define the approximating cost function as the least unconstrained cost,

$$\hat{C}\left(\hat{g}_R\right) = Min\left\{C\left(g_R\right) \middle| \hat{g}_R = i^t g_R\right\}.$$

This information would be easy to evaluate before the dispatch.

Construct the ORDC for responsive reserves that modifies (13) to incorporate the minimum or last resort reserves X priced at v. Here $Lolp\left(r\right) = \text{Probability}\left(\text{Net Load Change} \geq r\right)$. For a candidate value of the aggregate responsive reserves define the corresponding value on the operating reserve demand curve:

(14)
$$\pi_R\left(r_R\right) = \begin{Bmatrix} Lolp\left(i^t r_R - X\right), & i^t r_R - X \geq 0 \\ 1, & i^t r_R - X < 0 \end{Bmatrix}$$
$$P_R\left(r_R\right) = v\pi_R\left(r_R\right).$$

This defines the ORDC for responsive reserves. With this definition, the price of energy is the marginal cost of energy plus the scarcity value, and is bounded by $VOLL$.

MULTIPLE EMERGENCY ACTIONS

The basic logic extends to the case where there are multiple stages of emergency actions triggered by a low level of responsive reserves. The price of reserves is defined by the willingness to pay at the margin to obtain an additional unit of reserves. If emergency actions have been taken ex-ante, then the willingness to pay will be at least the cost of the emergency action. In addition, the value of reserves would be at least the ex-post value of an increment of reserves given the probability distribution of the change relative to the anticipated dispatch of the net load.

For example, suppose that we have three emergency actions, with limited capacity, where only the last requires involuntary curtailment of load at the full VOLL. Let the first two actions have values of emergency action $VEA_1 < VEA_2 < VOLL$, and available capacities KEA_1, KEA_2. Define the contingency minimum for reserves at X_3 where the VOLL applies. Let the other breakpoints be:

$$\begin{aligned} X_2 &= X_3 + KEA_2 \\ X_1 &= X_2 + KEA_1 \end{aligned}.$$

Then define $\upsilon\left(s\right)$, including the minimum contingency levels and emergency actions, as the greater of the ex-ante cost and the expected cost of using the emergency action given the level of reserves in the event that there is a deviation for the forecast net load.

(15) $$\upsilon(s)=\begin{cases} VOLL, & s \le X_3 \\ Max\left(VOLL * Lolp(s-X_3), VEA_2\right), & X_3 \le s \le X_2 \\ Max\begin{pmatrix} VOLL * Lolp(s-X_3)+ \\ VEA_2 * \left(Lolp(s-X_2)-Lolp(s-X_3)\right), VEA_1 \end{pmatrix}, & X_2 \le s \le X_1 \\ VOLL * Lolp(s-X_3)+VEA_2 * \left(Lolp(s-X_2)-Lolp(s-X_3)\right) & \\ +VEA_1 * \left(Lolp(s-X_1)-Lolp(s-X_2)\right), & X_1 \le s \end{cases}.$$

Hence, the ex-ante scarcity value for reserves is $P_R(r_R)=\upsilon(r_R)-\overline{c}$.

If the two emergency values are high enough, then given an operating reserve level r above the total $X+KEA_1+KEA_2$, the marginal value of an increment of responsive operating reserves would be:

$$\begin{aligned} P_R(r) &= VEA_1\left[Lolp(r)-Lolp(r+KEA_1)\right]+VEA_2\left[Lolp(r+KEA_1)-Lolp(r+KEA_1+KEA_2)\right] \\ &\quad +VOLL\left[Lolp(r+KEA_1+KEA_2)\right]-\overline{c}. \end{aligned}$$

This is the expected value component of the ORDC. The full ORDC in the dispatch would include the steps in the emergency response, and the probabilistic value of additional reserves, as in (15).

Figure 22

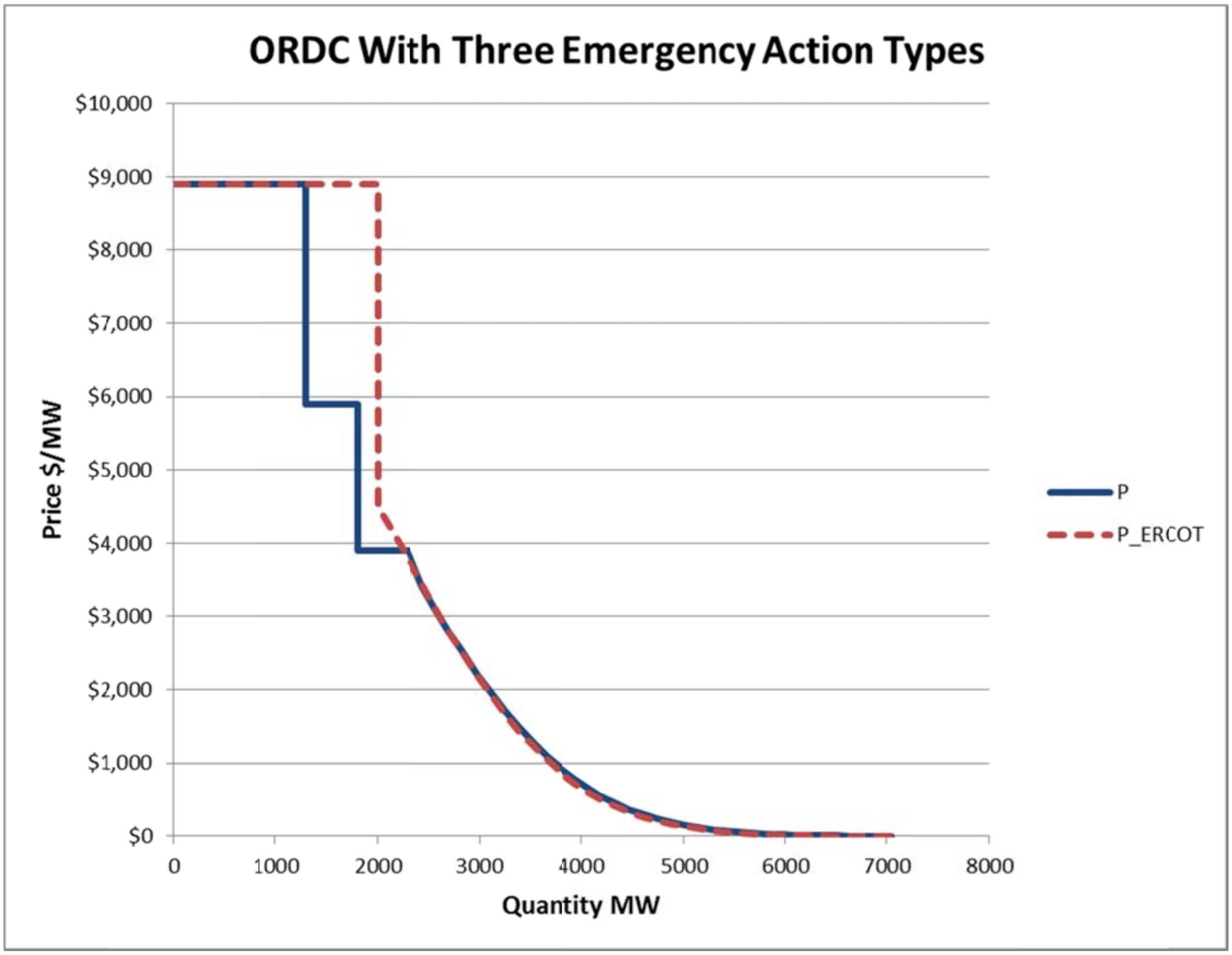


Figure 22 shows an illustrative case with the first emergency action at $4000/MW for 500MW, the second at $6000 for 500MW, and the final X value of minimum contingency reserves at 1300MW with a VOLL=$9000/MW. The corresponding emergency action "X_1" value is then at 2300MW. The comparison is with the initial ERCOT ORDC as implemented with X=2000MW and VOLL=$9000.[109]

[109] The basic assumptions for the illustrative normal distribution of changes in net load are

Expected Total (MW)	16
Std Dev (MW)	1357.00
VOLL ($/MWh)	9000
Marginal Dispatch ($/MWh)	100

MULTIPLE RESERVE TYPES

The organized market practice distinguishes several types of reserves. Setting aside regulation, the principal distinction is between “responsive” reserves (R) and “non-spin” reserves (NS). The ORDC framework can be adapted to include multiple reserves. This section summarizes one such modeling approach and relates it to the co-optimization examples above. The main distinction is that “responsive” reserves are spinning and have a quick reaction time. These reserves would be available almost immediately and could provide energy to meet increases in net load over the whole of the operating reserve period. By comparison, non-spinning reserves are slower to respond and would not be available for the entire period.

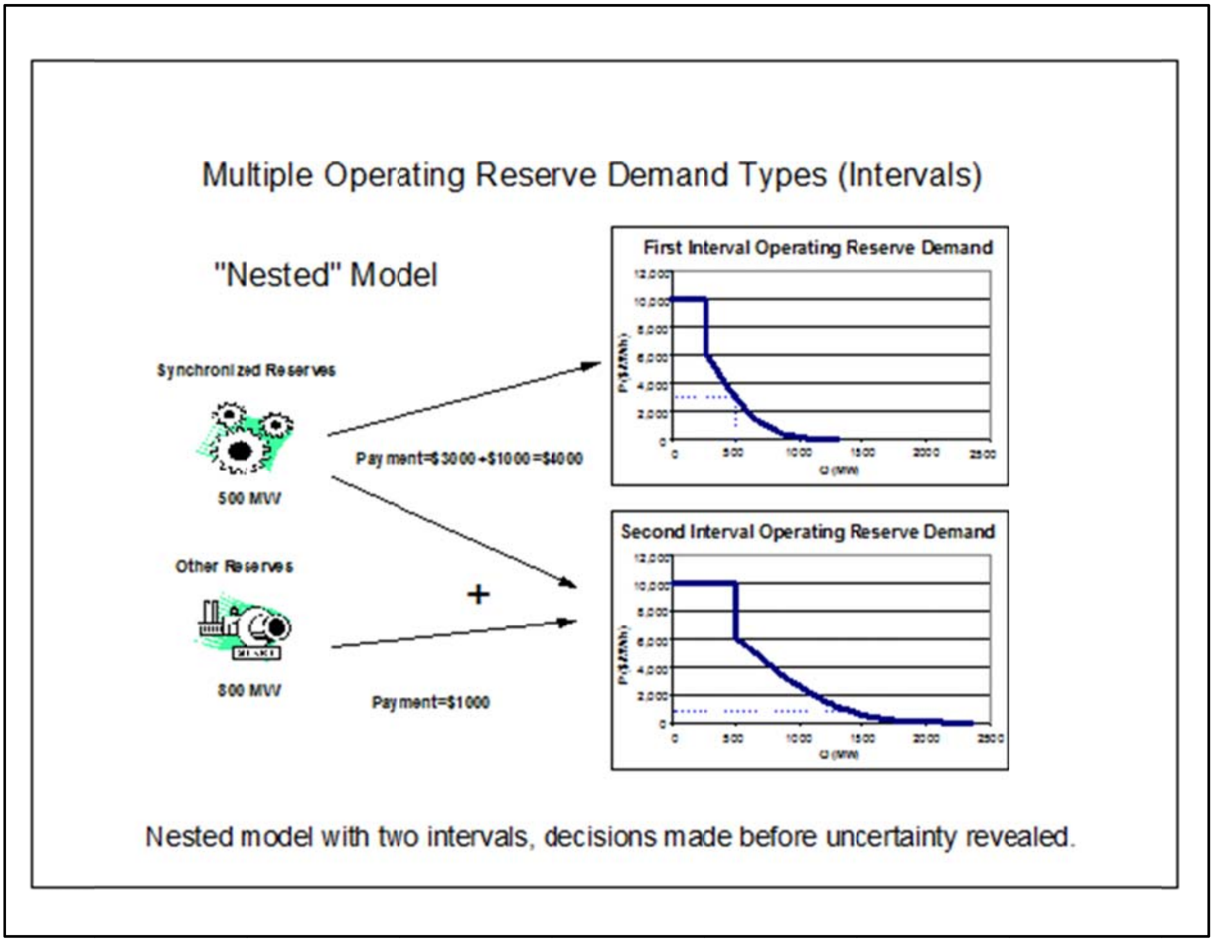
The proposed model of operating reserves approximates the complex dynamics by assuming that the uncertainty about the unpredicted change in net load is revealed after the basic dispatch is determined. The probability distribution of change in net load is interpreted as applying the change over the uncertain reserve period, say the next hour, divided into two intervals. Over the first interval, of duration (δ), only the responsive reserves can avoid curtailments. Over the second interval of duration (1-δ), both the responsive and non-spin reserves can avoid involuntary load shedding.

This formulation produces different values for the responsive and non-spin reserves. Let *v* be the net value of load curtailment, defined as the value of lost load less the avoided cost of energy dispatch offer for the marginal reserve. The interpretation of the prices of reserves, P_R and P_{NS}, is the marginal impact on the load curtailment times $Lolp$, the probability of the net change in load being greater that the level of reserves, r_R and r_{NS}. This marginal value differs for the two intervals, as shown in the following table:

Marginal Reserve Values		
	Interval I	Interval II
Duration	δ	1-δ
P_R	$vLolp_I\left(r_R\right)$	$vLolp_{I+II}\left(r_R + r_{NS}\right)$
P_{NS}	0	$vLolp_{I+II}\left(r_R + r_{NS}\right)$

This formulation lends itself to the interpretation of Figure 22 where there are two periods with different demand curves and the models are nested. In other words, responsive reserves r_R can meet the needs in both intervals and the non-spinning reserves r_{NS} can only meet the needs for the second interval.

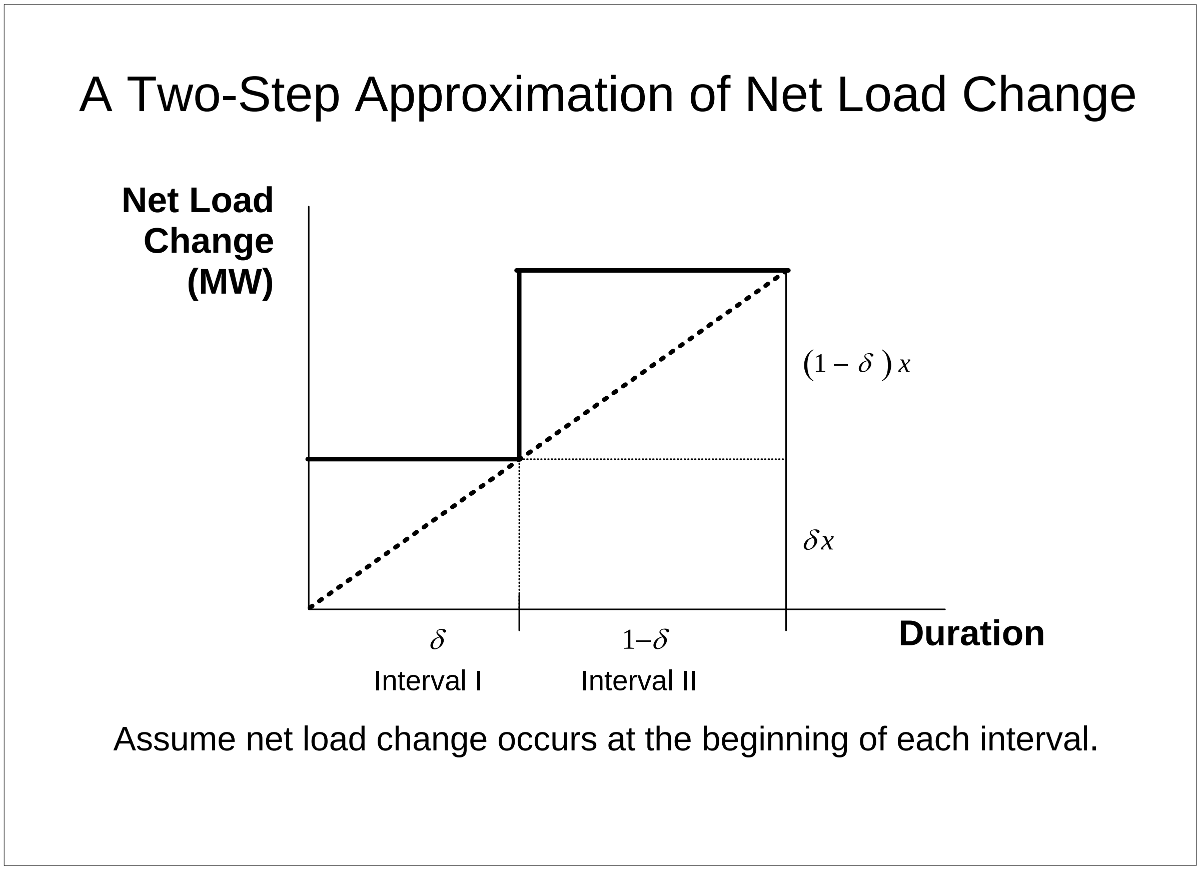
Figure 23



In order to keep the analysis of the marginal benefits of more reserves simple, there is an advantage of utilizing a step function approximation for the net load change. (This keeps the marginal value in an interval constant, and we don't have to compute expectations over the varying net load change. We only need the total LOLP over that interval.)

The standard deviation of the change in net load is for the total over the period. If the change is spread out over the period, then on average it would be more like the diagonal dashed line Figure 24. An alternative two-step approximation in Figure 24 that the net load change in the first interval, when only responsive reserves can respond, is proportional to the total load change, and the second step captures the total change at the beginning of the second interval.

Figure 24



During the first interval, only the responsive reserves apply. In the second interval, both responsive and non-spin reserves have been made available to help meet the net change in load. Suppose that there are two variables y_I, y_{II} representing the incremental net load change in the two intervals. Further assume that the two variables have a common underlying distribution for a variable z but are proportional to the size of the interval. Then, assuming independence and with x the net load change over the full two intervals, we have:

$$E\left(y_I\right)=E\left(\delta z\right)=\delta E\left(z\right),$$
$$E\left(y_{II}\right)=E\left(\left(1-\delta\right)z\right)=\left(1-\delta\right)E\left(z\right).$$
$$Var\left(y_I\right)=Var\left(\delta z\right)=\delta^2 Var\left(z\right),$$
$$Var\left(y_{II}\right)=Var\left(\left(1-\delta\right)z\right)=\left(1-\delta\right)^2 Var\left(z\right).$$
$$E\left(z\right)=E\left(y_I+y_{II}\right)=E\left(x\right)=\mu.$$
$$Var\left(x\right)=Var\left(y_I+y_{II}\right)=Var\left(y_I\right)+Var\left(y_{II}\right)=\left(\delta^2+\left(1-\delta\right)^2\right)Var\left(z\right).$$
$$Var\left(z\right)=\frac{Var\left(x\right)}{\delta^2+\left(1-\delta\right)^2}=\frac{\sigma^2}{\delta^2+\left(1-\delta\right)^2}.$$

The distinction here is that the implied variance of the individual intervals is greater compared to the one-draw assumption, even though the total variance of the sum over the two intervals is the same. This is simply an impact square root law for the standard deviation of the sums of independent random variables.

Hence, for the first interval, the standard deviation is $\frac{\delta\sigma}{\sqrt{\delta^2+\left(1-\delta\right)^2}}$, where σ is the standard deviation of the net change in load over both intervals.

Here the different distributions refer to the net change in load over the first interval, and over the sum of the two intervals. The distribution over the sum is just the same distribution for the whole period that was used above. Then $y_I \sim Lolp_I, y_I+y_{II} \sim Lolp_{I+II}$. A workable approximation would be to utilize the normal distribution for the net load change.

As before, there would be an adjustment to deal with the minimum reserve to meet the max contingency. The revised formulation would include:

$$\pi_R\left(r_R\right)=\begin{Bmatrix} Lolp_I\left(i^t r_R-X\right), & i^t r_R-X\ge 0 \\ 1, & i^t r_R-X<0 \end{Bmatrix}$$
$$\pi_{NS}\left(r_R,r_{NS}\right)=\begin{Bmatrix} Lolp_{I+II}\left(i^t r_R+i^t r_{NS}-X\right), & i^t r_R+i^t r_{NS}-X\ge 0 \\ 1, & i^t r_R+i^t r_{NS}-X<0 \end{Bmatrix}$$
$$P_R\left(r_R,r_{NS}\right)=v*\left(\delta*\pi_R\left(r_R\right)+\left(1-\delta\right)*\pi_{NS}\left(r_R,r_{NS}\right)\right),$$
$$P_{NS}\left(r_R,r_{NS}\right)=v*\left(1-\delta\right)*\pi_{NS}\left(r_R,r_{NS}\right).$$

This formulation lends itself to implementation in the co-optimization model. For example, given benchmark estimates for each type of reserves, $\left(\hat{r}_R,\hat{r}_{NS}\right)$, the problem becomes separable in responsive and non-spin reserves. A numerical integration of $P_R\left(r_R,\hat{r}_{NS}\right)$ and $P_{NS}\left(\hat{r}_R,r_{NS}\right)$

would produce the counterpart benefit functions, $R_I\left(r_R^0\right), R_{II}\left(r_{NS}^0\right)$. With weak interactions between the types of reserves, the experience with this type of decomposition method suggest that updating the benchmark estimates in an iterative model could produce rapid convergence to the simultaneous solution (Ahn & Hogan, 1982).

MULTIPLE ZONES AND LOCATIONAL OPERATING RESERVES

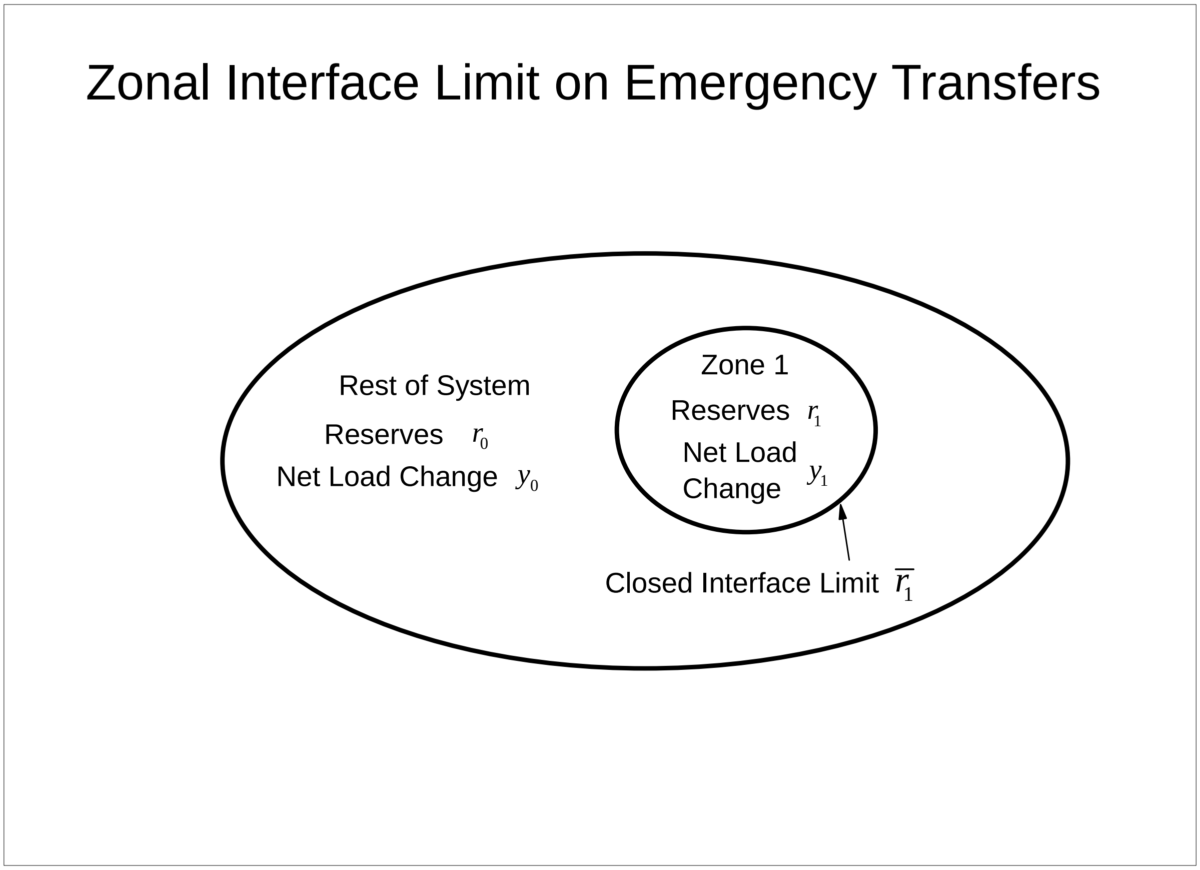
The assumption that there is a single system-wide operating reserve benefit may need to be modified. The steady-state constraints of transmission limits and loop flows apply to the base dispatch. These constraints need not apply necessarily to the short-term use of operating reserves in stressed situation. However, it is possible a set of transmission limits includes locational constraints on operating reserves. An approach for modeling locational operating reserves is to define a zone and the associated interface constraint that limits the emergency movement of power. This constraint then separates the reserves inside and outside the region and defines their interaction.

The task is to define a locational operating reserve model that approximates and prices the dispatch decisions made by operators. To illustrate, consider the simplest case with one constrained zone and the rest of the system. The reserves are defined separately and there is a known transfer limit for the closed interface between the constrained zone and the rest of the system. This zonal interface constraint would be analogous to the Capacity Emergency Transfer Limit in PJM planning models (PJM, 2016). The probability distribution for net load changes would be estimated separately for locations inside and outside the zone. The zonal requirements for operating reserves that interact with energy and economic dispatch, incorporate local interface constraints, and provide compatible short-term prices for operating reserves and interface capacity. This basic argument leads to a simple numerical model that can incorporate multiple embedded zones and interface constraints and be implemented with the co-optimization framework for energy and reserves.

An outline of the basic framework illustrates the representation of locational operating reserve demand curves. Adaptation of a single system ORDC to address locational reserve requirements raises additional issues.

To illustrate, consider the simplest case with one constrained zone and the rest of the system, as Figure 25. The regions are nested, meaning that the locational requirement is a subset of the system requirement. The reserves are defined separately for the system and within the local region, but they interact and there is a known transfer limit for the closed interface between the constrained zone and the rest of the system.

Figure 25



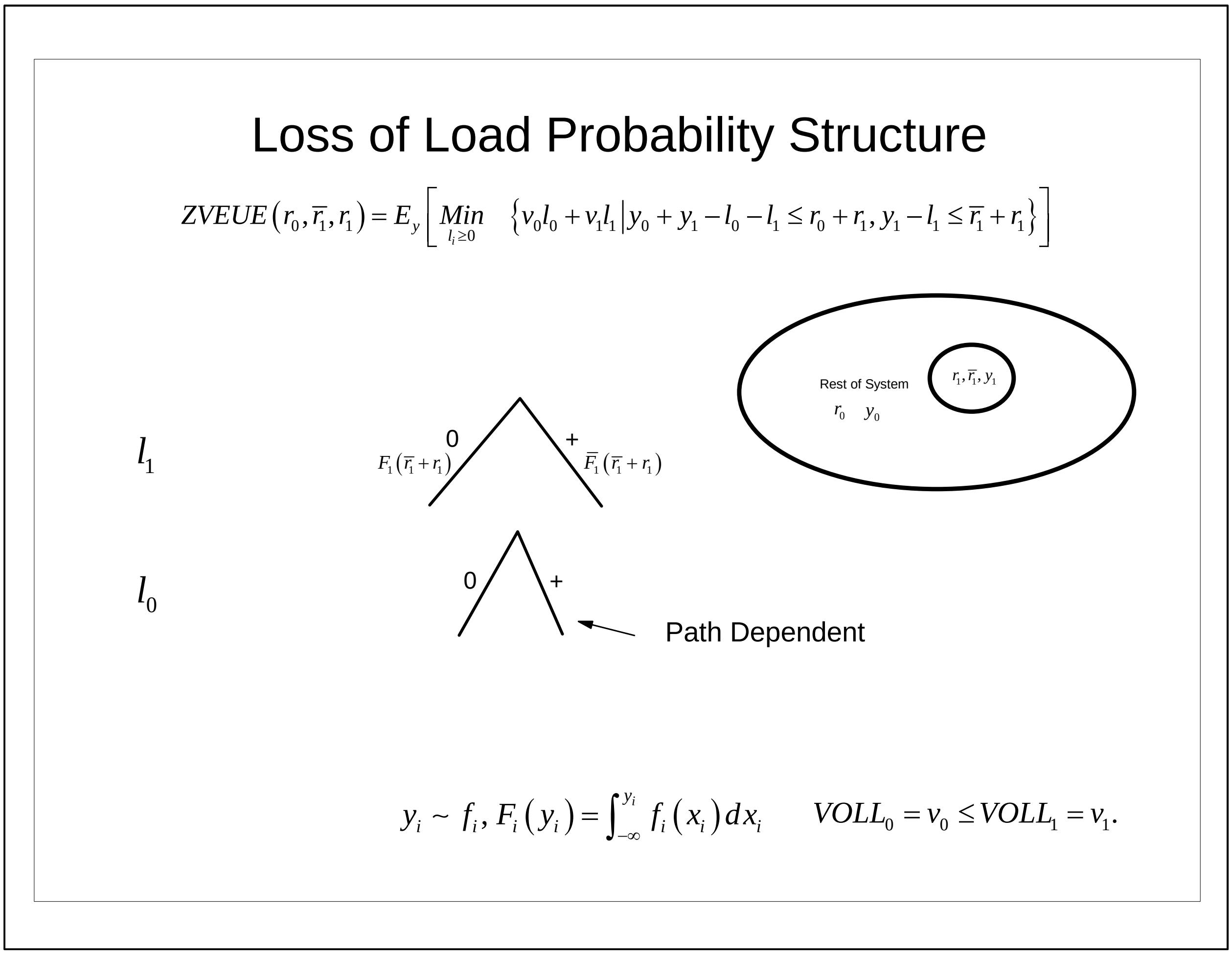
The interior Zone 1 has a known level of reserves r_1. The distribution of net load changes within the zone is $y_1 \sim f_1$. The closed interface defines the interior zone by a limit $\overline{r}_1$ on the aggregate power flow from the rest of the system into the local zone. This limit will interact with the dispatch power flow. The rest of system has a known level of reserves r_0 and a distribution of net load changes outside of the interior zone, $y_0 \sim f_0$. These are treated as independent distributions. Independence is not a strong assumption. The dispatch load forecast might be strongly interacting across the zones, but the unanticipated deviations from the forecast can be viewed as approximately independent across the zones.

The distributions for each net load change have corresponding cumulative distributions.

$$y_0 \sim f_0, y_1 \sim f_1, F_o\left(y_0\right) = \int_{-\infty}^{y_0} f_0\left(x_0\right) dx_0, F_1\left(y_1\right) = \int_{-\infty}^{y_1} f_1\left(x_1\right) dx_1 .$$

The zonal value of expected unserved energy (ZVEUE) would be an added component of the objective function in economic dispatch. Here, assume that the $v_1 = VOLL_1$ is at least as great as the corresponding value in the rest of the system, $v_0 = VOLL_0$. With this assumption, we assume the protocol that gives priority to meeting load deviations inside zone relative to the rest of the system, and the ex-post dispatch will have a simple structure. In Figure 26, the first priority is to meet the net change of load within the interior zone. The unserved load l_i will be penalized at the respective value of loss load.

Figure 26



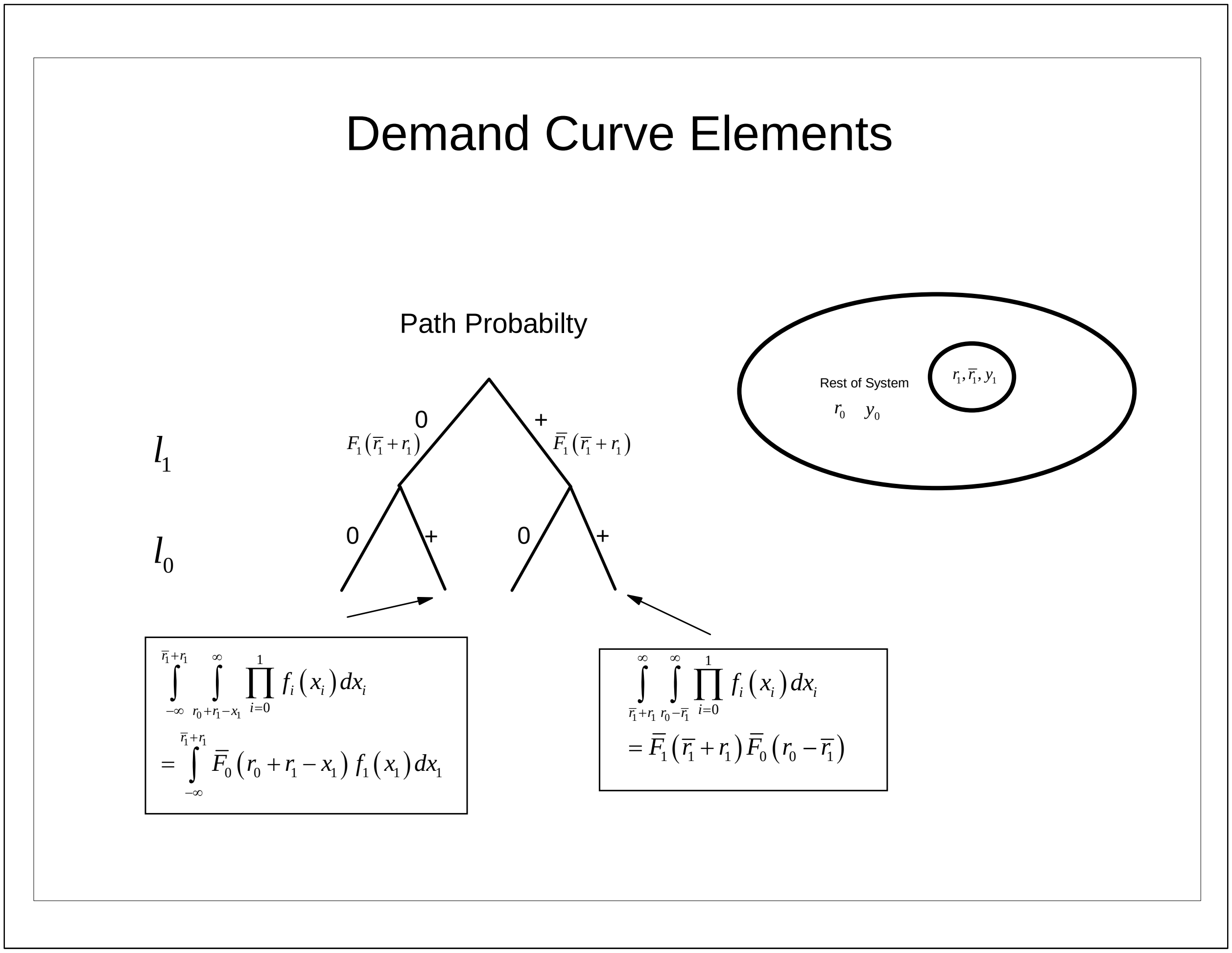
The basic problem determines the configuration of lost load and the ZVEUE.

$$ZVEUE(r_0, \overline{r}_1, r_1) = E_y\left[\underset{l_i \geq 0}{Min} \quad \{v_0 l_0 + v_1 l_1 | y_0 + y_1 - l_0 - l_1 \leq r_0 + r_1, y_1 - l_1 \leq \overline{r}_1 + r_1\}\right].$$

The derivatives of ZVEUE define the demand curves for operating reserves. The tree structure in Figure 27 illustrates the steps to construct these prices for reserves and the interface constraint. At the top of the branching is the amount of lost load in region 1. This is either zero or positive, and the probabilities on the branches apply for these conditions. The key is the limit on internal reserves and the interface limit. If the net change in load inside the zone is greater than $\overline{r}_1 + r_1$ then all the reserves inside the region and all that could move from outside the region would be utilized, and there would be loss of load inside the region. This occurs with probability $\overline{F}_1\left(\overline{r}_1 + r_1\right) = 1 - F_1\left(\overline{r}_1 + r_1\right)$. Likewise, the left branch with $l_1 = 0$ has probability $F_1\left(\overline{r}_1 + r_1\right)$.

The probabilities for the next level down are path dependent, but the calculation is conceptually straightforward.

Figure 27



For example, in Figure 27, given that we are on the path with $l_1 \geq 0$, the reserves available for the rest of the region must be the total rest-of-system reserves minus the interface capacity, because the interface capacity is being used to meet requirements in the constrained zone. The conditional probability of this case is $\overline{F}_0\left(r_0 - \overline{r}_1\right)$. Hence, the probability for the full path is $\overline{F}_1\left(\overline{r}_1 + r_1\right)\overline{F}_0\left(r_0 - \overline{r}_1\right)$, as shown in Figure 27. A similar argument applies to the other paths.

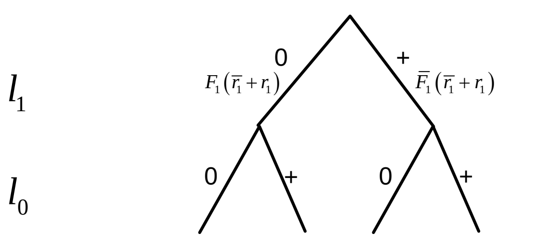
The full ZVEUE is difficult to characterize and calculate. However, inspection of the possible configurations of outages reveals the marginal zonal values of unserved energy, which define the locational demand curves for operating reserves.

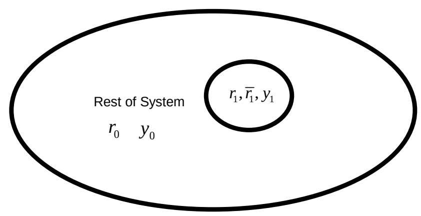
Figure 28

Loss of Load Values

$$ZVEUE\left(r_0, \overline{r}_1, r_1\right) = E_y\left[\underset{l_i \geq 0}{Min} \quad \left\{v_0 l_0 + v_1 l_1 \,\middle|\, y_0 + y_1 - l_0 - l_1 \leq r_0 + r_1, y_1 - l_1 \leq \overline{r}_1 + r_1\right\}\right]$$

Reserve Incremental Values





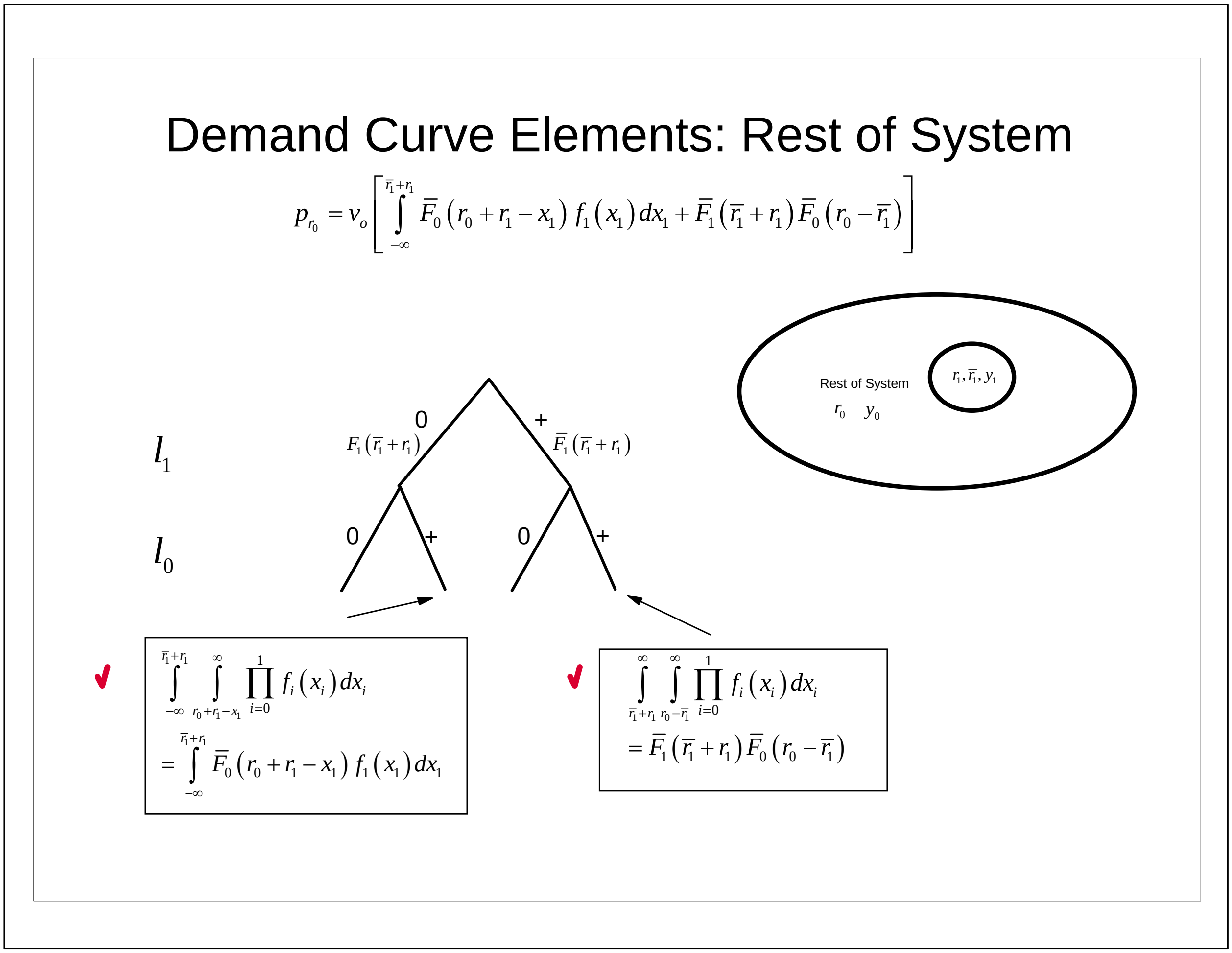
r_1	0	v_0	v_1	v_1
$\overline{r}_1$	0	0	v_1	$v_1 - v_0$
r_0	0	v_0	0	v_0

The table in Figure 28 illustrates the reserve incremental values on each of the paths. For example, on the right-most path, the marginal value of reserves inside the region is v_1 and the marginal value in the rest of the region is v_0, because there are load losses in both regions. On this same path, the marginal value of incremental interface capacity is the increased flow from outside to inside, which would produce net benefit $v_1 - v_0$. Similar arguments apply to the other elements of the table. And with this table we see the paths where values are non-zero and we need the associated path probabilities.

Combining the marginal values and probabilities for each path in the tree yields the corresponding value which defines the expected marginal value of the increment of reserves or interface capacity.

For example, Figure 29 shows the demand curve for the price of reserves in the rest of the system, with the check marks showing the relevant paths.

Figure 29



The demand is a function of all three elements and the associated probability distributions.

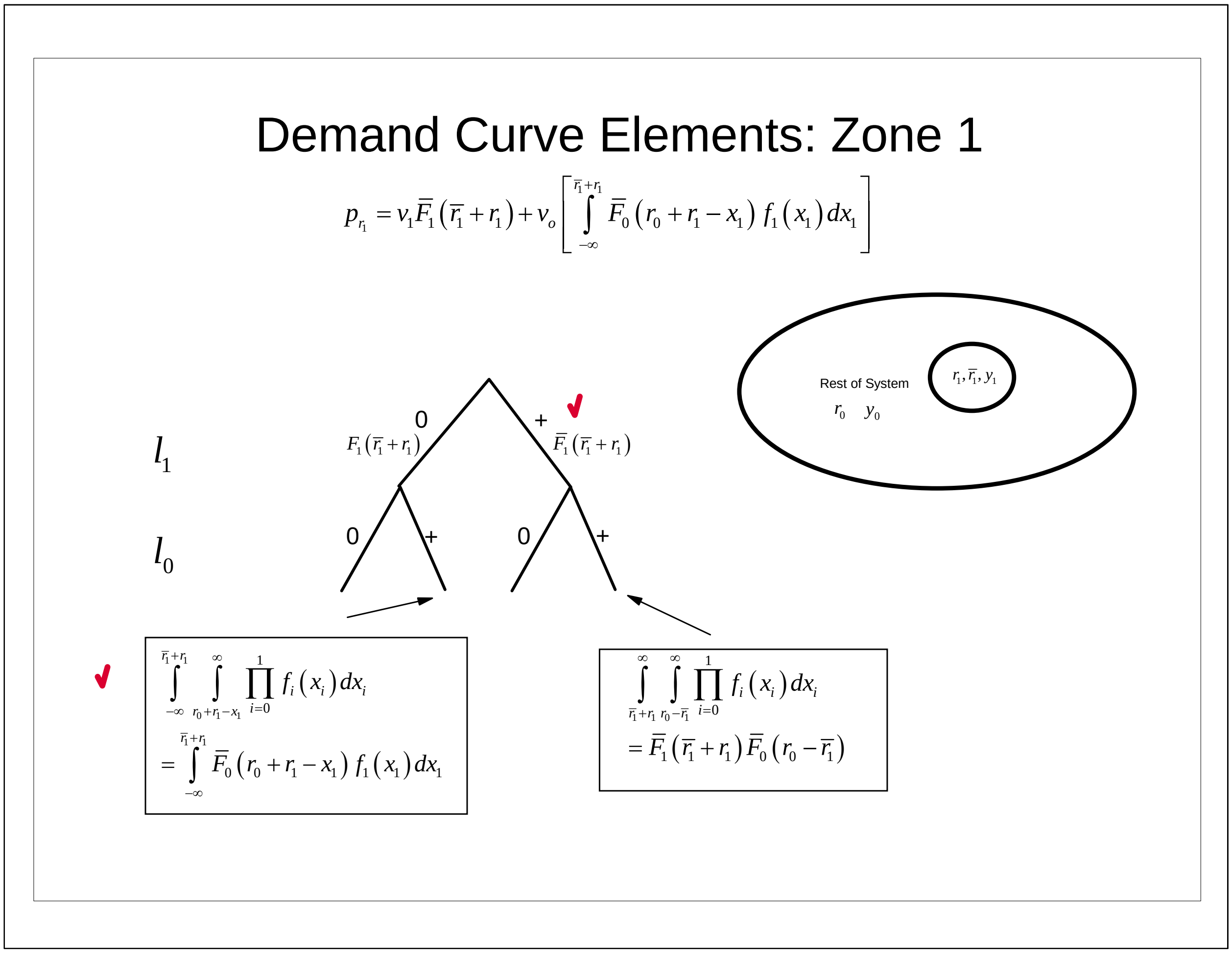
$$p_{r_0} = v_o \left[\int_{-\infty}^{\overline{r}_1 + r_1} \overline{F}_0 \left(r_0 + r_1 - x_1 \right) f_1 \left(x_1 \right) dx_1 + \overline{F}_1 \left(\overline{r}_1 + r_1 \right) \overline{F}_0 \left(r_0 - \overline{r}_1 \right) \right].$$

Since all these elements are known, it is a simple calculation to trace out the elements of the demand curve to include in the dispatch objective function and solve for energy and reserves.

There is a similar story for the price of reserves inside the local zone in Figure 30.

$$p_{r_1} = v_1 \overline{F}_1\left(\overline{r}_1 + r_1\right) + v_o \left[\int_{-\infty}^{\overline{r}_1 + r_1} \overline{F}_0\left(r_0 + r_1 - x_1\right) f_1\left(x_1\right) dx_1 \right]$$

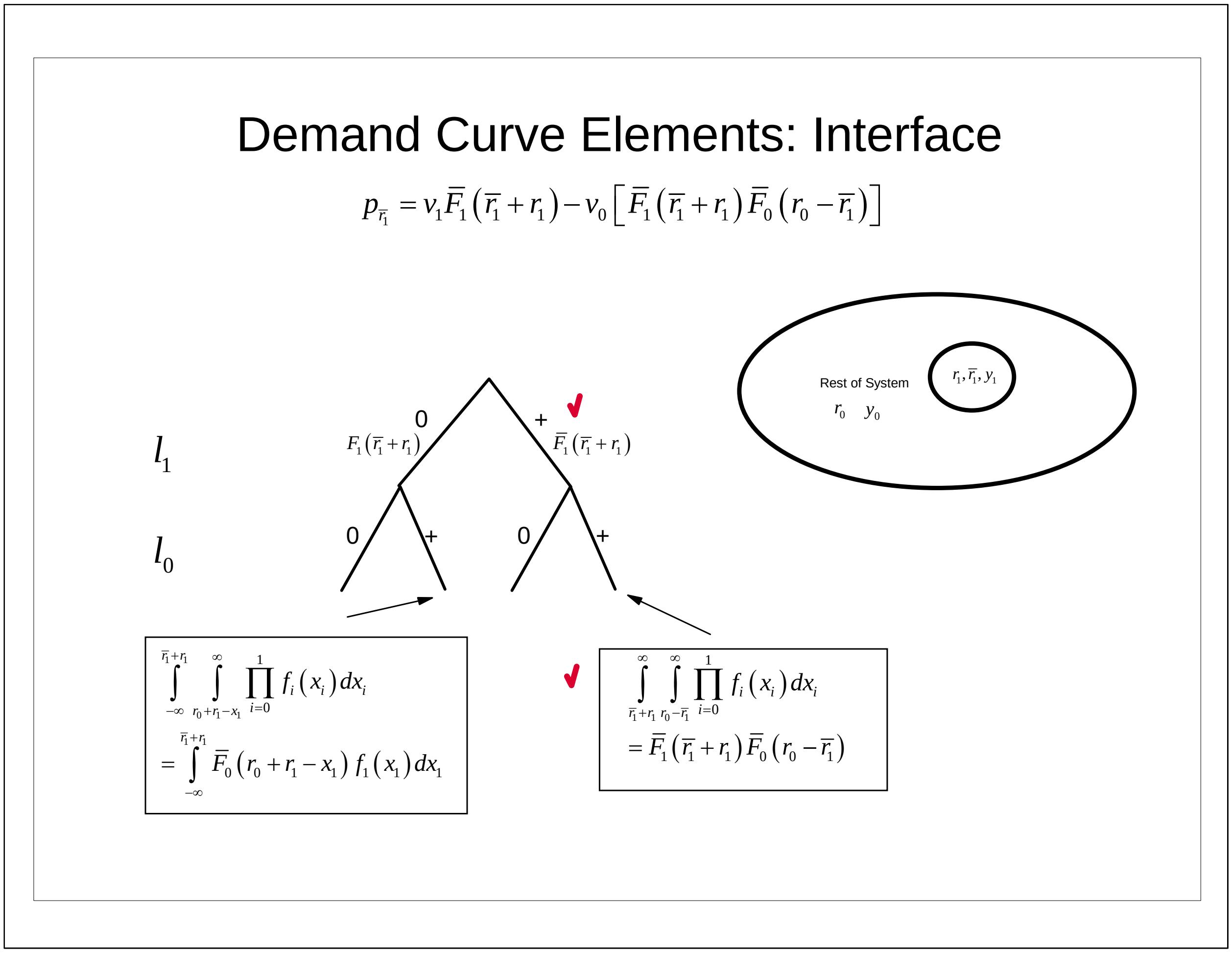
Figure 30



Finally, the analysis extends to the demand curve for interface capacity in Figure 31 .

$$p_{\overline{r}_1} = v_1 \overline{F}_1\left(\overline{r}_1 + r_1\right) - v_0 \left[\overline{F}_1\left(\overline{r}_1 + r_1\right) \overline{F}_0\left(r_0 - \overline{r}_1\right) \right]$$

Figure 31

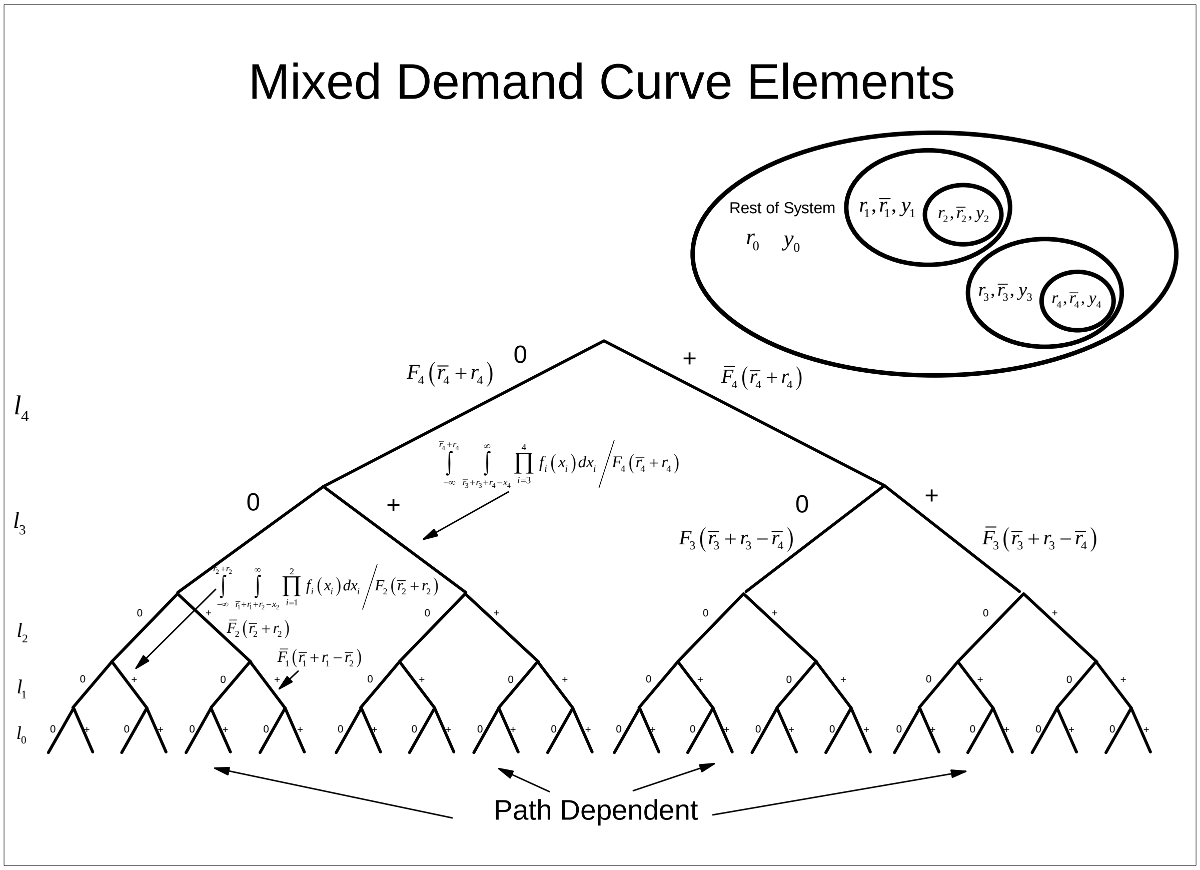


Although the values for each reserve differ in each case on the tree, the expected values defining the reserve prices satisfy $p_{r_i} = p_{r_0} + p_{\bar{r}_1}$.

The extensions to include multiple zones or further nested zones would follow a similar logic. At some stage the "curse of dimensionality" would make the size of the probability tree too large to maintain computational tractability. However, the simple structure could well accommodate a few zones.

The illustration in Figure 32 suggests the basic structure with parallel and nested zones. On each path there would be an algorithm for numerically integrating the probabilities to obtain the path weights. And there would be a corresponding table of marginal values of each zonal reserve and interface constraint (Hogan, 2010). The resulting demand curves could be included in the dispatch logic.

Figure 32



Separable Demand Curve Approximation

In all cases, the price for reserves and the interface constraint are functions of all the reserve components. Furthermore, the relationships are not separable. One implication is that the scarcity prices are not simply additive, and the highest price in a region can never be higher than the value of lost load for that region. However, unlike the case of a single regional ORDC, the construction of the counterpart of $R_k\left(r_k\right)$ requires more than simply integrating under the prices along a single dimension.

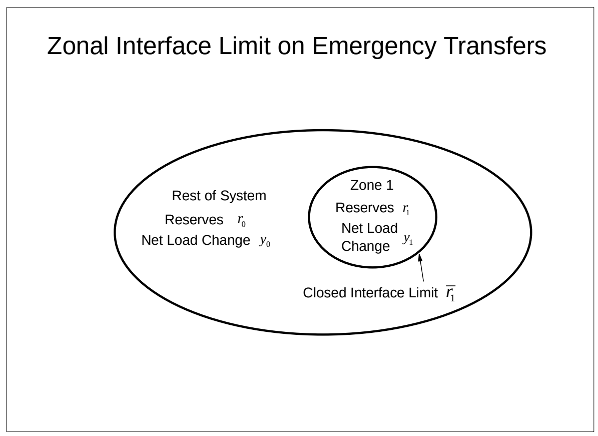
A requirement to construct a counterpart of (1) is to have integrated functions $\hat{R}_k\left(r_o,\overline{r}_1,r_1\right)$ such that at the optimal solution $\left(r_0^*,\overline{r}_1^*,r_1^*\right)$ the derivatives equal the respective prices. For the single constrained zone and rest of the system, an example of a separable version of such a function would be:

$$
\begin{aligned}
\hat{R}(r_0) &= \int_0^{r_0} p_{r_0}\left(r_0, \overline{r}_1^*, r_1^*\right) \\
\hat{R}(\overline{r}_1) &= \int_0^{\overline{r}_1} p_{\overline{r}_1}\left(r_0^*, \overline{r}_1, r_1^*\right) \\
\hat{R}(r_1) &= \int_0^{r_1} p_{r_1}\left(r_0^*, \overline{r}_1^*, r_1\right)
\end{aligned} \quad . \tag{16}
$$

Implementation of these approximations utilizes an estimate of a reasonable version of the dispatch solution. The better the estimate, the better the approximation. Iteration on the estimate could be combined with the dispatch search algorithm in a manner that would implement the path model numerically without significant computation difficult. This iteration with (16) would be a variant of the PIES method for non-separable demand model and computing equilibria (Ahn & Hogan, 1982).

An example illustrates the separable implementation of three locational reserve-related demand curves. The parameter assumptions and an assumed benchmark provide the components for the approximation.

	ROS	Zone 1
Expected Total (MW)	107.10	45.90
Std Dev (MW)	488.99	209.57
VOLL ($/MWh)	7000	10000



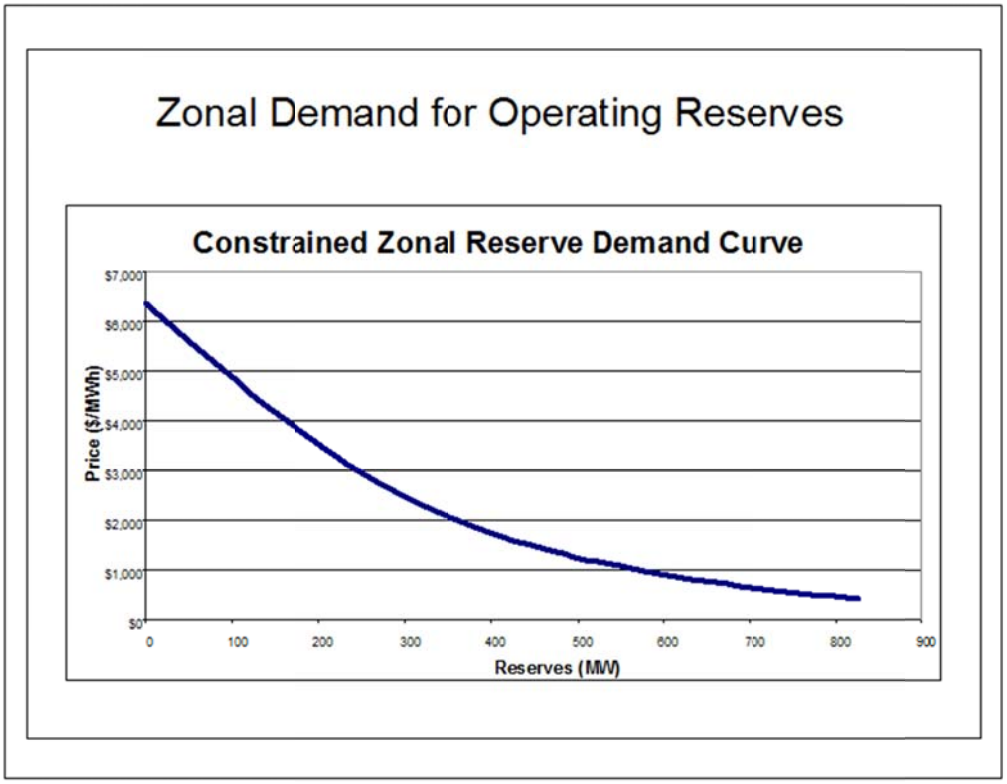
	ROS	Zone 1	Interface
Benchmark (MW)	160.65	68.85	45.90

With these assumptions, we can use the normal approximation of the net load changes to calculate the corresponding probabilities on each path and the resulting estimates of the reserve-related prices.

For the price in the constrained zone we have:

$$p_{r_1} = v_1\left(1 - F_1\left(\bar{r}_1 + r_1\right)\right) + v_0 \int_{-\infty}^{\bar{r}_1 + r_1} \left[1 - F_0\left(r_0 + r_1 - x_1\right)\right] f_1\left(x_1\right) dx_1$$

Figure 33

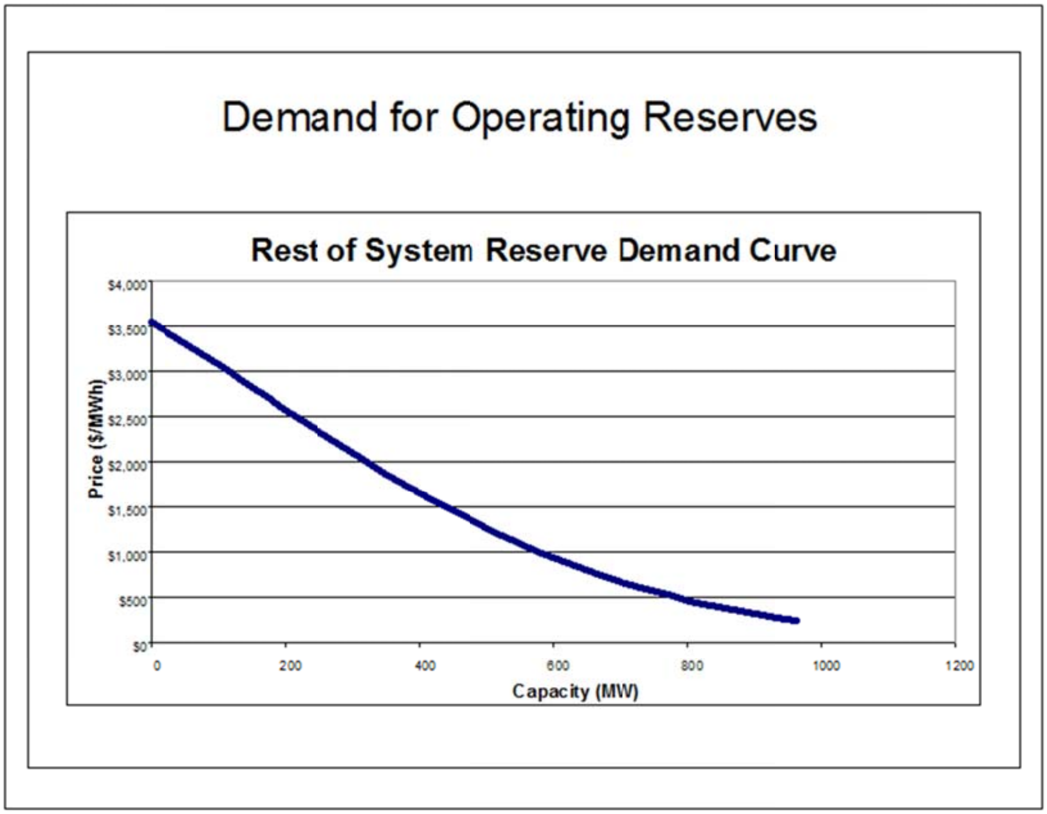


The maximal zonal price in Figure 33 is slightly over $6000/MWh, determined by the value of lost load and the loss of load probability.

For the price of reserves on the rest of the system we have:

$$p_{r_0} = v_0 \int_{r_0 - \bar{r}_1}^{\infty} \left[1 - F_1\left(r_0 + r_1 - x_0\right)\right] f_0\left(x_0\right) dx_0$$

Figure 34

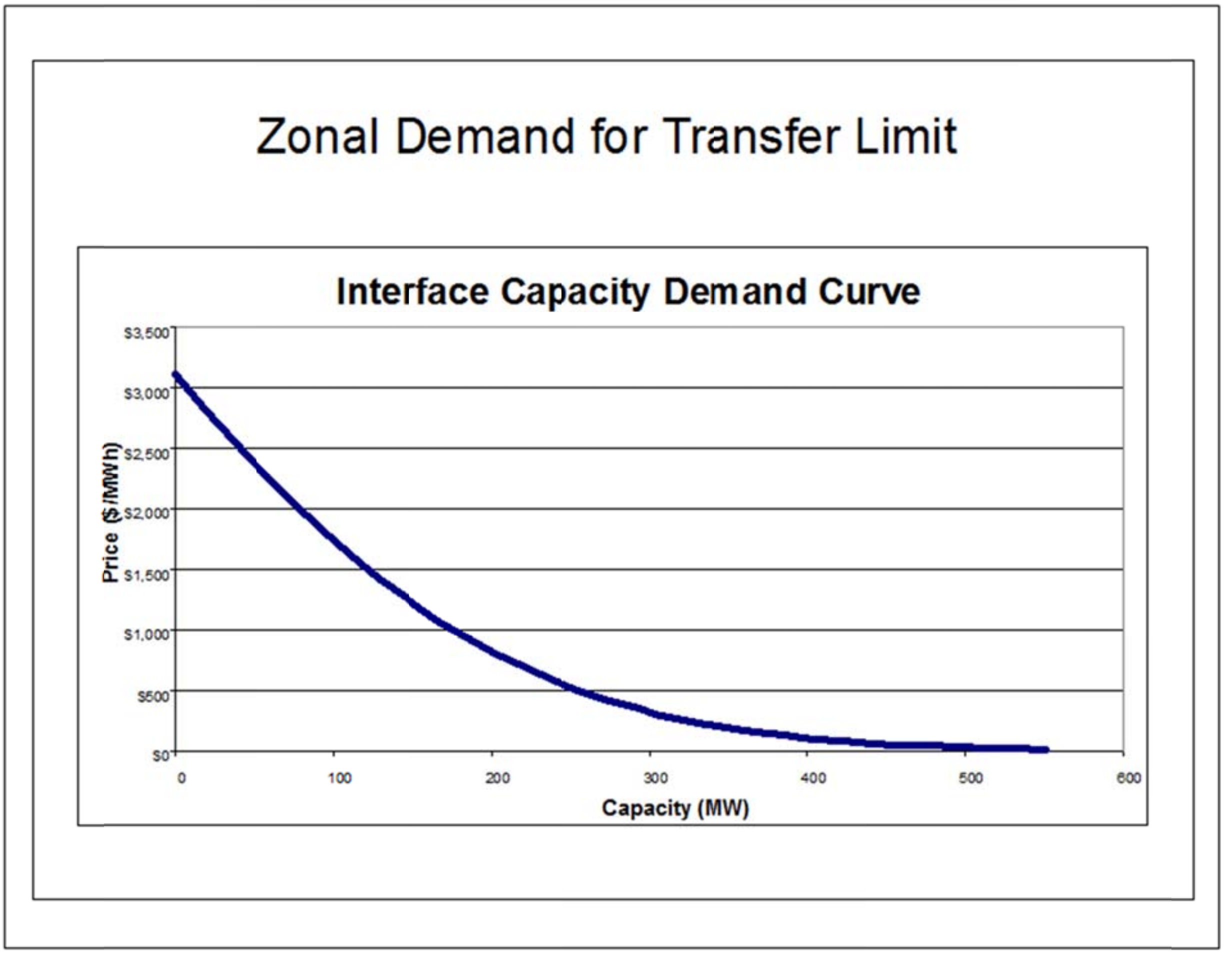


The maximal rest of the system price in Figure 34 is slightly over $3500/MWh, determined by the lower value of lost load and the loss of load probability.

For the interface constraint, the price is:

$$p_{\bar{r}_1} = v_1\left(1 - F_1\left(\bar{r}_1 + r_1\right)\right) - v_0\left(1 - F_0\left(r_0 - \bar{r}_1\right)\right)\left(1 - F_1\left(\bar{r}_1 + r_1\right)\right)$$

Figure 35



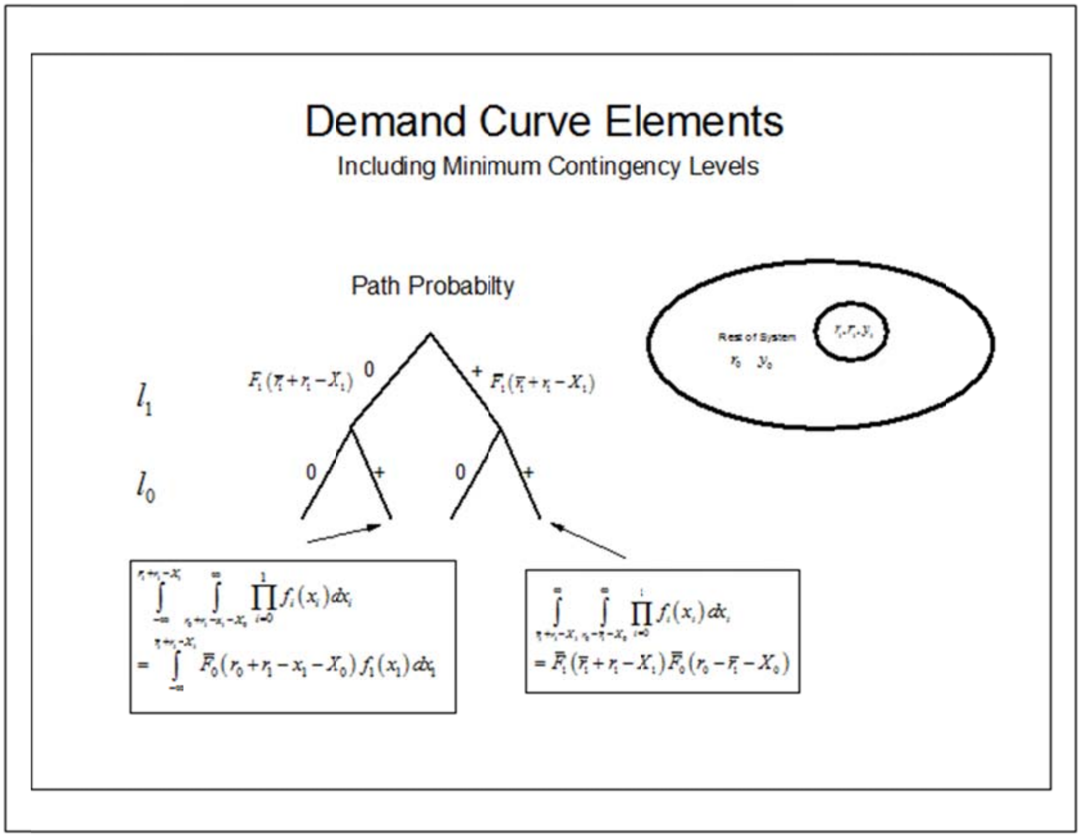
The maximal interface capacity scarcity price in Figure 35 is slightly over $3000/MWh, determined by the differences in the values of lost load and the loss of load probability.

Zonal Contingency Requirements

The zonal demand curves would be modified to include minimum contingency requirements for emergency action such as a curtailment of load at the respective $VOLL$. The impact would be to change the path probability calculation to reflect the effect of the minimum contingency level.

For example, the revised version of the two critical path probabilities in Figure 27 would appear as in Figure 36.

Figure 36



An extension to include multiple types of emergency actions would require further analysis. In particular, the simple paths in the various probability trees arise because of the protocol that loss of load inside the constrained region takes precedence over that outside the region. If there are many emergency steps modeled, the optimization assumption might upset this protocol. However, if the administrative response decisions adhere to this protocol, then the simple tree structure and locational operating reserve demand curves should remain as well.

Co-Optimization with the Locational Demand Curves Interface Constraint

The design of the ORDC allows for co-optimization with the energy dispatch. A modified version of the dispatch co-optimization problem in (1) would include these reserve functions in the objective and add a constraint that captures the interaction of energy and reserves in the locational transfer limit. Hence, represent aggregate loads as:

$$y = \begin{pmatrix} y_0 \\ y_1 \end{pmatrix} .$$

Let K_{Int1} be the total interface constraint. The net load demand inside the local constraint is $i^t y_1$, and this must be met by ex-ante dispatch of generation in the rest of the system. This dispatch of energy utilizes part of the ex-ante estimate of the interface capacity. That residual $\overline{r_1}$ is available for the transfer of reserves. Hence, the added constraint in the combined energy and reserve dispatch would be:

$$i^t y_1 + \overline{r_1} \leq K_{Int1} \ .$$

The result of co-optimization of reserves and energy would induce scarcity prices for reserves and the interface constraint that affect the locational price of energy.

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