Resource Adequacy and Energy-Only Market Design:

Assessing The Impact of ERCOT's Operating Reserve Demand Curve[1]

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Abstract: I examine the effect of an Operating Reserve Demand Curve (ORDC) which was recently implemented in Texas to assist power producers in recovering their fixed investment costs. I characterize and employ an economic plant dispatch model to examine the ORDC's effects on representative natural gas plants in Texas, allowing me to determine whether or not the ORDC is likely to induce new capital deployment. I find that the ORDC's positive effects are minimal and likely negated by the policy's complexity, sending unclear signals to prospective investors. My results suggest that the policy itself is insufficient to incentivize the construction of new generation capacity in Texas's electricity market.

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Dedicated to my parents,
Laurel and Ferris.

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I. Introduction

As of this writing, Texas's electricity market is quietly developing the potential for a serious crisis which could cost the state more than $18 billion over the next fifteen years if unaddressed (Plewes, 2013). Third-party analysis from an independent monitor shows that the market's net revenues[2] in both 2012 and 2013 were insufficient to support continued generation investment;[3] if sustained, this revenue inadequacy would eventually lead to a higher likelihood of outages and electricity price spikes, presenting real economic costs for Texas residents and businesses (Potomac, 2013; Potomac, 2014). These negative repercussions would be resultant from insufficient generation capacity[4] within the state, allowing electricity demand to sporadically eclipse total supply, which would in turn cause blackouts and rotational load-shedding.[5] In order to prevent this outcome, the Public Utility Commission of Texas (PUCT)[6] must incent the construction of new generation by providing revenues outside of the traditional energy payment stream.

The goal of ensuring that adequate system capacity exists to meet a market's forecast demand, commonly referred to as "resource adequacy," is a key focus of new energy

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[2] I use the term net revenues interchangeably with "net revenue," "energy margin," "merchant generation margin," "short-run profit," "peaker net margin," "net margin," and "generation margin." Net revenue is the total revenue received from electricity generation that can be earned by a power plant less the plant's short-run production costs. In other words, it is the total revenue in excess of short-run operating costs which can be put toward fixed and capital cost recovery (Potomac, 2013).
[3] Infrastructure or generation investment generally refers to the construction of new power plants.
[4] Generation capacity refers to the maximum amount of power that a given plant or set of plants is capable of generating. It is crucial that markets have adequate generation capacity to meet even the highest levels of consumer demand, or else a blackout will occur.
[5] Rotational load-shedding, shedding, or load-shedding refers to involuntary curtailment of electricity consumption by a system operator to avoid grid failure during shortage conditions.
[6] The PUCT is a state regulatory oversight body which is tasked with maintaining the efficiency, reliability, and adequacy of Texas' regional electric network (PUCT, 2011).

proposals across the United States. The capital intensive nature and extended construction periods of the electricity sector require that market operators pay specific attention to long-term supply levels and investment incentives in order to prevent a power grid from becoming unreliable. New resource adequacy policies must incorporate significant foresight in order to account for plant closures, demand growth forecasts, environmental regulations, and a significant margin of error (FERC, 2012).

While substantial thought and analysis characterizes the planning phase of every new policy, it is relatively rare to find third-party empirical economic work devoted to the evaluation of a single policy ex post its implementation. In this paper, I analyze the implementation of an Operating Reserve Demand Curve (ORDC or "the curve") in the market operated by the Electric Reliability Council of Texas (ERCOT).[7] The ORDC is intended to help provide resource adequacy by consistently raising the market price of electricity within ERCOT, incentivizing new infrastructure investment by allowing market participants to recover more of their fixed costs (Hogan, 2012).

As recently as September, 2014, ERCOT's independent monitor reported that the ORDC's ability to provide shortage revenues of sufficient magnitude to spur capacity investment was unclear and that the curve would require continued monitoring and evaluation (Potomac, 2013). This paper is accordingly the first independent empirical study of the ORDC following its commencement of operation on June 1, 2014. The ORDC itself is a centerpiece of a school of thought for electricity market design known as "energy-only"

[7] ERCOT was the first Independent System Operator to be created in the United States. It is governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. The electric grid operator serves 24 million customers and 85% of electricity demand in the state of Texas (PUCT, 2011; ERCOT, 2014).

design. The findings of this paper regarding the curve's efficacy therefore are of serious import not only to ERCOT and its customers but more importantly to the larger field of resource adequacy theory and electricity market design.

The purpose here is to examine whether or not the ORDC's implementation in ERCOT has reliably raised electricity prices to the point where market entrants would be incentivized to construct new generation capacity. I answer this question by examining the magnitude and frequency of price additions in ERCOT's real-time electricity market from June 1, 2014 to January 31, 2015, "the study period," to determine if the ORDC provides adequate fixed cost recovery to support new investment. I evaluate the ORDC's price additions from the perspective of a potential investor, projecting net revenue additions for a prospective power plant and comparing them to fixed costs of market entry and existing plant profit margins in order to determine whether or not the market is signaling that an investment would be profitable. All of my analysis focuses on the addition of peaking natural gas plants to ERCOT's market, as these represent the cheapest and most readily available form of capacity that could be purchased by a potential investor (Newell, 2012; Hogan, 2013; EIA, 2014).

I find that the ORDC is a sub-optimal policy to promote resource adequacy in ERCOT. In combination with the curve's lack of transparency and consistency, its minimal benefit to producer net energy margin presents an unclear investment signal that is unlikely to persuade otherwise uninterested sources of capital. The structure of the remainder of the paper is as follows: in Section II, I provide additional background on electricity markets and Texas' ORDC. Section III delivers an overview of contributing literature within resource adequacy theory. In IV, I give overviews of the theory and methodology behind resource adequacy economics, electricity pricing, ORDC construction, and the capacity market alternative. In V, I examine my data for both ERCOT market information and expected peaking plant costs. Section VI then describes the specific steps I take to evaluate the ORDC's success, Section VII presents this study's results, and VIII concludes.

II. Background

II.i. How Electricity Markets Work

Electric utilities and power generators were successfully regulated for a significant portion of their existence in the United States. For many years in the first half of the twentieth century, the cost of producing power steadily declined as utilities built increasingly large and efficient plants. Increasing demand for electricity coupled with these production efficiencies yielded simultaneous decreases to consumer electricity prices and increases to utility earnings. The landscape for regulated utilities began to change dramatically in the late 1900's as fuel costs became progressively less stable, coming to a head with the U.S. Oil Embargo of the 1970's. Sustained increases in oil and gas prices pressured the margins of utilities whose topline revenue was restrained by regulated electricity rates. Utilities responded by favoring the construction of capital-intensive coal and nuclear plants over those fired by expensive natural gas and oil, leading to an increase in fixed costs that was eventually passed on to consumers. As a result, the 1970's and 1980's brought routine requests for rate increases from utilities that often faced bankruptcy. Eventually, this led to retail customer complaints as utility rates continued to escalate faster than U.S. gross domestic product (Warwick, 2002).

Beginning in the early 1990's, regulatory oversight boards such as the CAISO (California), ERCOT (Texas), and PJM (mid-Atlantic U.S.), began to turn to "reconstruction" or deregulation of electricity markets with the hope of returning lower prices to consumers. Since this deregulatory process began, economists have debated and experimented with various designs but still have not come to a full consensus over which market mechanisms are most effective to produce efficient and reliable deregulated electricity markets.

Because there is currently no economically viable method for storing electricity on an industrial scale, all power must be produced in real-time by power plants and demand-side generators before being sold to distributing utilities that deliver the power to consumers' homes. This market where electricity generators sell to utilities is known as the wholesale market. It is important to have an elementary understanding of the fundamental differences between regulated and unregulated wholesale electricity markets in order to provide a framework for understanding the remainder of the paper, so I will provide a brief overview here.

In a regulated market, state regulatory officials determine power prices such that every system participant is guaranteed a certain allowed rate of return on their existing investments. This approach shields consumers from spikes in the cost of their electricity and assures both producers and distributors of electricity that new investments in grid and generation technology will result in increased profit. For example, if an electricity producer has been approved to construct a new power plant by the market's regulatory board, the producer will be certain that it would make a positive return by building the plant. Under this design, market participants are eager and willing to invest in new power plants whenever regulators deem necessary, meaning that the market's operator has control of the amount of installed capacity in the system (Warwick, 2002).

In a deregulated market, wholesale electricity prices are allowed to fluctuate based on where demand from electricity distributors meets the cost curve of the system's producers.

In the short run, supply is fixed and the demand curve for electricity is nearly perfectly inelastic because consumers are rarely presented with a price associated with powering up a light bulb or factory. This means that the eventual clearing price per unit of power will be determined by the variable opportunity cost of the marginal power plant needed to produce a certain demanded quantity of electricity (Hogan, 2013). The mechanics of this auction process require that every power producer submit a bid that constitutes the amount of electricity it is willing to produce along with the price it is willing to produce at. The market operator then calls on, or dispatches, plants in order of increasing cost from lowest to highest. Every producer in the system is then paid an identical price for each unit of generation regardless of their own marginal cost. This system characterizes a uniform-price, multi-unit auction in which all power producers are incentivized to submit bids to produce at their own marginal costs (Hortacsu, 2007; Cramton-Stoft 2007).

The deregulated model described above poses significant problems for "peaking plants," which are only called upon during rare times of peak demand. Because peaking plants have the highest marginal costs, there are very few times when the eventual clearing price for power is significantly above their variable expenses. It is therefore intrinsically difficult for peaking plants to recoup their fixed investment costs when they are only paid for the power they produce. Typically, a peaking plant would recover its fixed costs during the rare occurrences of extreme conditions on the power grid which send electricity prices skyward. However, regulatory bodies such as CAISO, ERCOT, and PJM attempt to protect their consumers from price spikes by capping the price of electricity at a predetermined level. This prevents prices from rising to the degree necessary for peaking plants to recover their fixed costs and leads to what is known as the "missing money problem." In the words of

Shmuel Oren, a professor at the University of California at Berkeley, prices of electricity are not high enough to pay for generation fuel and also cover the investment in new plants. Business people are looking at this and they're deciding it is not a profitable business (Chediak, 2012).

This problem of missing money represents a subset of a larger field of study known as resource adequacy. Resource adequacy is the maintenance of an adequate level of capacity to guarantee the reliability of an electricity system. Solutions aimed at establishing resource adequacy look to incentivize investment in generation capacity (power plants) through various market mechanisms including auctions, reliability targets, and financial contracts. Because investment in new generation capacity is crucial to counterbalance plant closures and additional demand for electricity, many deregulated markets have searched for ways to solve the missing money problem, thereby encouraging investment and ensuring resource adequacy (Joskow-Tirole, 2007).

There are three primary design tracks for resolving resource adequacy within competitive wholesale markets in the United States. The first is known as the installed capacity (ICAP) track. Advocates of this market design believe that investors should be directly compensated for the construction of power plants, thereby ensuring the market that a certain amount of capacity will be built in any given year and reducing risk premiums for investors (Singh, 2000). The second school of thought has been termed the energy-only design track and is centered on the idea that consistently higher spot prices for electricity should be used to attract new investment and simultaneously incentivize performance from existing capacity (Hogan, 2005). The third and final design track is known as the convergent track. The convergent track combines elements from the ICAP and energy-only tracks to provide investors with both capacity payments and performance incentives in the form of higher spot prices (Cramton, 2006).

The Pennsylvania, Jersey, Maryland (PJM) Interconnection Company, which operates a deregulated market in the mid-Atlantic United States, is an advocate of the convergent design track. PJM holds annual capacity auctions, wherein investors are assured compensation three years in advance simply for promising to eventually build power plants. This solves the missing money problem by directly paying power producers to invest in new generation and automatically covers a portion or the entirety of their fixed costs (PJM, 2012). The cost is eventually passed along to consumers in the same way that they directly pay for network maintenance and electricity drawn from the grid. Although heretofore successful in PJM and other restructured markets, the creation of capacity auctions deviates from the energy-only market design described above because power producers are paid simply to build generation capacity.

This paper focuses on an alternative route to solving the missing money problem. Markets dedicated to the energy-only market structure have but one channel through which they may increase remuneration to power producers in order to help them recover their fixed costs – the price of electricity. I examine the approach taken by Texas's grid operator, which focuses on consistently raising the price of electricity to encourage new investments in generation technology.

II.ii. Texas and the Operating Reserve Demand Curve

The Electricity Reliability Council of Texas (ERCOT) operates a grid servicing 24 million customers and 85% of Texas's electricity load, constituting a $35 billion annual market (ERCOT, 2014). The early 2000's brought a large increase in total generating capacity for ERCOT, as producers sought entry to a newly restructured electricity market with the hope of extracting significant profit. From 1999 to 2009, ERCOT added generation units at a rate of more than 25 per year, totaling 279 units over the span of the decade (Potomac, 2010). In 2003, this investment pace allowed the market to enjoy a reserve margin[8] of over 20% (Plewes, 2013).

Unfortunately, the investment pace of more recent years has painted a bleaker picture for ERCOT's resource adequacy. 2010 and 2011 saw a total of only 9 new generation units added at a pace of 4.5 per year (Potomac, 2012). Similarly, the market's realized reserve margin dropped to 14.3% in 2014 and is expected to be below ERCOT's target level by 2017 (NERC, 2014). Figure 1 displays the North American Electric Reliability Corporation's[9] (NERC's) anticipated resource planning reserve margin for ERCOT against NERC's own reference reserve margin of 15.00% and ERCOT's target reserve margin of 13.75% (NERC, 2015). The graph shows that without substantial new investment, ERCOT's current

[8] Reserve margin generally refers to the amount of installed generation capacity in excess of forecasted demand. It is calculated as $(CAP_E - QD_E)/QD_E$ where CAP_E is the expected maximum available supply and QD_E is the maximum expected available demand. Oversight bodies and grid operators use the reserve margin as a metric by which to evaluate a system's resource adequacy.

[9] NERC is a non-profit corporation founded in 2006 with the intention of promoting reliability and resource adequacy within the eight restructured U.S. power markets. It was created out of the Energy Policy Act of 2005, which called for an independent non-governmental self-regulatory organization for enforcing mandatory reliability standards in the United States. NERC applied for and received this designation in 2006 (NERC, 2013).

resources will fail to keep pace with anticipated load growth and plant closures. Work by independent experts including the Brattle Group, Potomac Economics, and Charles River Associates further bolsters the argument that ERCOT's current wholesale market design is in need of reform to avoid dangerously low reserve margins for the foreseeable future (Newell, 2012; Plewes, 2013; Newell, 2014; Potomac, 2014).

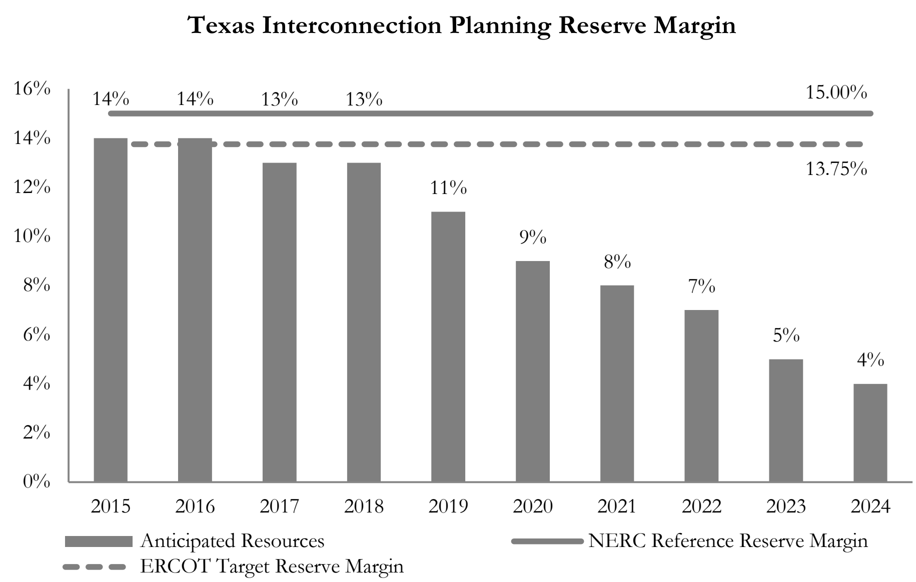

Figure 1: Anticipated summer planning reserve margin for the Texas Interconnection, compared with select reference margins (NERC, 2015).

The PUCT has acknowledged that lack of support for new power plant construction is of concern to the system, requesting a number of resource adequacy proposals and studies over the past decade (Newell, 2011; Hogan, 2012; Newell, 2012; ERCOT-Hogan, 2013; Newell, 2014; Potomac, 2014). As of this writing, ERCOT is the only restructured market which follows an energy-only market design, meaning that all other deregulated markets hold capacity auctions or provide capacity payments to producers (Anderson, 2014). The PUCT's commissioners believe that a capacity market would impose billions of dollars in incremental system costs in order to retain a certain reserve margin, but note that even a mandated reserve margin fails to completely preclude the possibility of rolling blackouts (Anderson, 2014). The commissioners note that ERCOT has never experienced a total grid failure to date, and that the two most recent rotational load-shedding events occurred when target margins were above the 15.00% NERC reference level (Anderson, 2014). In response to inadequacy forecasts such as the one displayed in Figure 1, the PUCT contends that an efficient energy-only market with substantial load-growth should always show an anticipated capacity margin shortfall four to five years from any assessment date[10] (Anderson, 2014).

However, Texas's major power producers insist that current conditions exhibit a major difference with those experienced from 1999-2009: electricity generation is no longer profitable (Chediak, 2012; O'Grady, 2014). A steady decline in natural gas prices since 2008 has propelled energy prices downward,[11] exposing unregulated power producers to significant losses. Sustained low electricity prices have already begun to affect the ability of producers to meet operating and capital obligations, precipitating the bankruptcies of Optim Energy LLC and Energy Future Holdings (EFH) in 2014 (Optim, 2014; EFH, 2014). Optim's bankruptcy filing cited adverse market conditions resultant from systematically lower net revenues, which affected the firm's ability to meet working capital obligations and

[10] This argument relies on the concept that reserve margins should be adequate, but that the maintenance of an overly high reserve margin forces unduly high system costs. The commissioners further mentioned that third-party reports have forecast imminent resource inadequacy without new capacity additions in 2005, 2006, 2008, 2009, and 2010 (Anderson, 2014).

[11] A decline in the price of natural gas translates directly to lower average electricity prices in ERCOT. This is because natural gas plants represent a large portion of ERCOT's generation capacity and are generally the price-setting plants during peak and shoulder-peak hours. Lowered natural gas prices flatten the supply stack by lowering the efficiency differential between gas plants that operate different combustion technologies. This directly translates to significantly lower net revenues for gas facilities in ERCOT by diminishing their margins during hours of highest demand.

debt service requirements (Optim, 2014). In January 2014, the four largest remaining power producers in Texas (NRG Energy, Calpine Corporation, NextEra Energy, and Exelon Corporation) took out a full-page newspaper ad warning that Texas could be destined for regular rolling blackouts without overhaul of ERCOT's market design (O'Grady, 2014). The companies simultaneously formed a coalition called Texans for Reliable Power, advocating for an invigorated approach to ensuring resource adequacy in ERCOT through increased energy revenues.

For their part, ERCOT and the PUCT appear to be assuring market participants that energy-only revenue streams are sufficient to ensure resource adequacy despite multiple market signals that electricity prices are too low to sustain existing producers, let alone new capacity investment. Maintaining the belief that a capacity market's costs outweigh its reliability benefits, ERCOT has instead attempted to reward producers by keeping electricity prices consistently higher. The mechanism by which they achieve this goal is known as an Operating Reserve Demand Curve (ORDC) and is the subject of this study.

On June 1, 2014, ERCOT implemented an ORDC in an effort to increase the efficiency, reliability, and adequacy of its electricity grid (ERCOT, 2014). The ORDC assigns value to the scarcity of electricity in ERCOT's real-time spot market. This attempts to compensate power producers for their provision of capacity during shortage conditions, specifically allowing peaking plants to recoup more of their fixed costs (Hogan, 2012). Because electricity supply and demand must meet at every second of the day, maintaining a healthy level of real-time reserves[12] is crucial to avoiding blackouts resultant from unexpected grid failures or spikes in demand. Real-time reserves therefore provide a stopgap for short-term scarcity by providing a margin of error for the grid's operator to correct temporary supply-demand imbalances. The ORDC assigns value to scarcity by monitoring the market's reserves,[13] raising the price of electricity via an artificial "price adder" in response to decreases in the level of real-time reserves.

This relationship is illustrated in Figure 2, which provides a visual approximation of the ORDC implemented last June. The level of reserves is represented on the horizontal axis while the value, or price, of those reserves is represented on the vertical axis. It should be evident from examining the curve that as the level of available reserves begins to fall towards zero, the curve will gradually raise the price of those reserves. Because producers should be indifferent between supplying reserves and actual power, any increase in the price of reserves is passed through to the real-time price of electricity.

The discontinuity in price at 2,000 MW of available reserves represents what is known as the reserve threshold. When the reserve threshold is reached, ERCOT will automatically assign the price of reserves to be equal to the maximum price of electricity in the system. In other words, if the maximum electricity price allowed in ERCOT is $9,000 per

[12] Real-time reserves represent the amount of generation capacity that is not actively providing electricity, but could be dispatched to do so instantaneously at any given point (literally the amount of capacity held in reserve from the real-time market). The grid operator maintains real-time reserves in order to prevent sudden demand spikes or plant failures from causing a supply-demand imbalance, which could force a blackout or load-shedding event. Generally, reserves are paid the same price as if they were providing electricity to the market.
[13] It is important to differentiate between real-time reserves for the purpose of the ORDC's calculation and total installed reserves for the purpose of long-term resource adequacy. When I discuss the ORDC's mechanics, "reserves" implies real-time reserves; when I discuss resource adequacy, "reserves" implies installed generation capacity in excess of long-term forecasted demand.

MWh, the curve will set prices equal to $9,000 per MWh whenever there are fewer than 2,000 MW of available reserves.

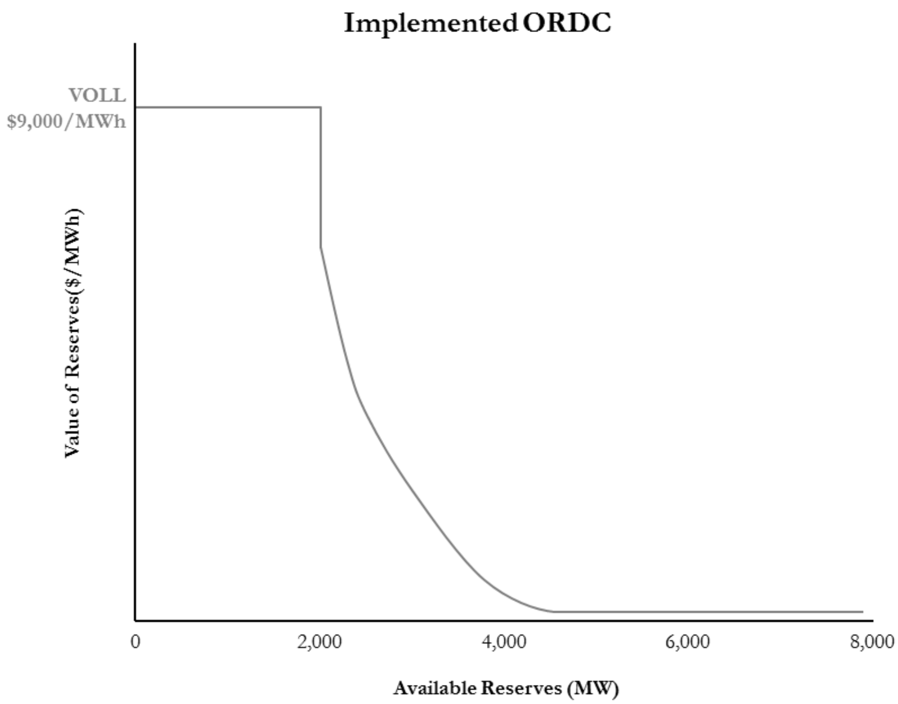

Figure 2: A visual approximation of the operating reserve demand curve (ORDC) enacted by ERCOT on June 1, 2014 (ERCOT, 2014).

The ORDC's price adder is embedded in the real-time spot price of electricity which producers use to make dispatch decisions and settle financial contracts. In its most basic form, the system-wide spot price for electricity can therefore be represented as:

$$\rho = Base\ Energy\ Price + Scarcity\ Adder \tag{1}$$

Where ρ represents the eventual clearing price, the $Base\ Energy\ Price$ represents the energy-only price of electricity, and the $Scarcity\ Adder$ represents the additional value from the ORDC. In ERCOT terminology, Equation 1 becomes:

$$RTSPP = RTLMP + RTORPA \tag{2}$$

Where the $RTSPP$ is the real-time settlement point price (ρ), the $RTLMP$ is the real-time locational marginal price (base energy price), and the $RTORPA$ is the real-time on-line reserve price adder (scarcity adder). For the purposes of my analysis, I treat the $RTORPA$ as additively separable from the $RTLMP$ on a time-weighted average basis. This implies that given the $RTSPP$ and $RTORPA$ for any given settlement interval, I can find the underlying energy-only price by manipulation of Equation 2:

$$RTLMP = RTSPP - RTORPA$$

A full derivation of the ORDC's additive separability from the real-time locational marginal price can be found in Appendix A and further overview of the concepts behind the ORDC's calculation can be found in Section IV.iii.

III. Literature Review

As mentioned in Section II.i., there are three primary design tracks for establishing resource adequacy in modern-day wholesale power markets. Here, I will provide an overview of the three tracks and discuss the positives and negatives of each, paying special attention to ERCOT's ORDC.

The ICAP, or capacity market, design track advocates for annual fixed payments to investors in return for plant construction. This class of approaches was designed specifically to replace the missing money caused by regulatory electricity price caps and restore resource adequacy by setting a target for installed capacity in the market. ICAP markets use an explicit capacity-demand function that pays investors more than enough to recover fixed costs via the annual capacity payments when capacity is below the market's target and less than enough when capacity is adequate. Joskow (2007) and Cramton and Stoft (2006) both discuss capacity markets in great detail. ICAP designs are successful in guaranteeing an adequate level of capacity in the system, solving the central resource adequacy problem at relatively low cost. Investors typically view risk as synonymous with cost, so the guaranteed coverage of a significant portion of fixed costs from capacity payments reduces investor risk premiums and hence the overall cost of enticing investment in the system (Cramton-Stoft, 2006).

However, traditional ICAP designs are criticized for not providing proper incentives for existing capacity to bid assets competitively into the market. For example, if a potential investor were aware that he would be given fixed payments for building a certain amount of generation capacity, say 500 MW, he would clearly attempt to procure the cheapest (and likely the least efficient) capacity available. This means that despite the purchase of adequate capacity, the system would be delivering unnecessary cost to its consumers in the form of decreased efficiency (Hogan, 2005). Critics of ICAP designs additionally point out that setting a capacity target represents a significant administrative interference in what should be a competitive market (Chao, 2006).

However, ICAP proponents say that certain elements of energy-only design represent a disguised but equally egregious administrative interference (Cramton, 2006). In order to understand this debate, it is important to have a grasp of the logic behind the energy-only design track. This approach takes a different tack to reaching wholesale market efficiency. Energy-only design favors the use of competitive electricity prices to properly incentivize asset construction and encourages or mandates complete hedging of electric load to protect consumers from price spikes. Wolak (2004), Chao-Wilson (2004), Oren (2005), and others call for the use of long-term hedging strategies to encourage competitiveness. Wolak (2004) accomplishes hedging via forward, bilateral power contracts while Chao-Wilson (2004) focuses on options and risk management. A string of approaches including Oren (2005), Bidwell and Henney (2004), and Bidwell (2005) all require markets to mandate that utilities purchase enough call-options from suppliers to hedge load at its highest potential peak levels. These approaches make important strides towards maintaining the reliability and efficiency of existing capacity, but largely ignore the fact that electricity spot prices are systematically too low for fixed cost recovery.

Hogan's (2005) paper on energy-only market design is significant in that it is the first energy-only design to acknowledge the problem of missing money and propose a direct solution via consistently higher spot prices of electricity. Hogan gradually solidified the ideas present in his (2005) paper into the operating reserve demand curve (ORDC) via additional papers in (2006), (2008), and (2012). As mentioned in Section II.ii., the ORDC assigns value to the scarcity of electricity and adds said value to the real-time spot price of electricity. This approach is criticized because calculation of the ORDC is dependent upon the market-maker's administratively set value of lost load (VOLL). VOLL is intended to be representative of the economic damage caused to a system by a reliability event, and is notoriously hard to calculate. Another ORDC parameter, the loss of load probability (LOLP) is typically based on historical distributions of electricity prices, which are not necessarily indicative of future distributions. ICAP and convergent design advocates argue that the ORDC therefore over-complicates market design, sends uncertain signals to investors, and still represents administrative interference in the market on par with ICAP's capacity targets (Cramton-Stoft, 2006).

In summary, energy-only approaches tend to succeed in incentivizing proper supply bidding and long-term hedging, while ICAP approaches more directly solve the resource adequacy problem. The convergent design track seeks to merge these two schools of thought by requiring a certain amount of capacity be built, while ensuring that newly constructed capacity is efficient and existing capacity is being efficiently bid. Convergent market designs include the annual capacity payments from ICAP designs, but further stipulate that each plant will be expected to provide a share of power generation equal to its share of capacity within the market (Cramton- Ockenfels, 2011). Plants which end up generating less power than would be expected given their capacity will be given a smaller capacity payment, while plants generating a surplus will be given a larger capacity payment.

In this way, the market is self-balancing. An investor may select a cheaper, less efficient form of generation, but the investor knows that in doing so, he or she is likely to receive a smaller capacity payment in return. Many convergent designs also utilize other energy-only market mechanisms such as load-hedging and higher spot prices to ensure competitiveness in the supply-bidding process. Singh (2000) was the first advocate of convergent market design and his theoretical ideas have since been developed and expanded upon by Bidwell-Henney (2004), Cramton-Stoft (2006), Cramton- Ockenfels (2011), and Cramton (2013).

Like ICAP markets, convergent design is criticized by energy-only advocates for interfering with pure-market forces that theoretically create efficient markets (Hogan, 2012). However, convergent design significantly reduces investor risk premiums and guarantees that a certain amount of capacity will be built into the system (Cramton-Stoft, 2006). This is because any investor approved by the capacity auction is guaranteed to cover a significant portion of his or her fixed cost, and the auction will pay out to new investors until the system-wide capacity target is achieved. The success of this program, like any resource adequacy program, does not hinge on one payment, but rather the signal to investors that regular payments of comparable magnitude will continue on into the future. For example, a resource adequacy program that was guaranteed to end tomorrow would not attract a single investor, because a recurring stream of payments would be necessary to recover fixed costs. As such, all ICAP and convergent designs provide relative assurance to investors that their fixed costs will be recovered if they are selected by the capacity auction.

By contrast, Hogan's ORDC relies upon reserve levels in any given hour to approximate the installed capacity adequacy of the system over the long run. Even if this approach does work *in expectation*, it still presents investors with increased risk because there is no guarantee of cost recovery in any given year.

The various papers which were discussed at length above may also be viewed below in summary form within Table 1:

	Year	Reliability Targeting	Replace Missing Money?	Years New Unit Covered	Contract Type	Price-Based Performance Incentives
Energy-Only Design Track						
Wolak: Contract Adequacy	2004	None	No	0	Financial	Weak
Chao-Wilson: Call-Options	2004	None	No	Yrs > 0	Physical	Weak
Oren: Call-Options	2005	None	No	0	Physical	Weak
Hogan: ERCOT ORDC	2012	Price	Yes	0	Financial	Yes
Convergent Design Track						
Singh: Combined Option ICAP	2000	Quantity	Partial	0	Physical	Weak
ISO-NE Market Design	2004	Quantity	Yes	0	Physical	Yes
Bidwell Henney: Call-Options	2004	Quantity	Yes	4	Physical	Weak
Cramton-Stoft: Forward Capacity	2006	Quantity	Yes	4-5	Physical	Yes
PJM Market Design	2007	Quantity	Yes	4	Physical	Yes
Capacity Market Design Track						
Northeast ICAPS	2004	Quantity	Yes	3	Physical	No
CRAM / PJM Proposal	2006	Quantity	Yes	0	Physical	No

Table 1: An overview of resource adequacy literature adapted and expanded from Cramton-Stoft's (2006) paper on forward capacity markets.

Over the past decade, many who have studied this problem have been swayed by the convergent design argument. PJM and other markets have implemented convergent market design to great success (PJM Staff, 2012; PJM Staff, 2014; Newell, 2014). They have largely solved their resource adequacy problem without noticeable erosion of plant quality. ERCOT, on the other hand, has found itself in an interesting predicament in that it is wedded to an energy-only market design via its previous policies and current beliefs, but acknowledges the legitimacy of the missing money problem in restoring resource adequacy. As such, they have selected Hogan's approach to restoring the missing money via implementation of the ORDC, making them the only deregulated electricity market in the United States which does not currently implement some form of capacity auction (ERCOT, 2014; Anderson, 2014).

The question for this paper is then whether or not the ORDC does enough to incentivize capacity investment given the presence of other existing policy alternatives. This study represents the first third party, empirical, academic work done in response to the implementation of ERCOT's operating reserve demand curve. The analysis found in this study is critical to promote unbiased understanding of sound market policy and to steer dialogue surrounding future market designs.

IV. Theoretical Framework

IV.i. Resource Adequacy Economics

Resource adequacy programs are best understood within the larger framework of power plant operation and profitability. Power markets exhibit short-run price competition over a commoditized product, but are additionally characterized by long-term barriers to new firm entry. These long-term barriers come in the form of high fixed investment costs and length regulatory approval processes, which prevent new firm entry when the market fails to generate enough short-run profits to cover the fixed cost of capital investment (Murray, 2009). As discussed above, no right-minded investor would choose to enter the market during a period in which the market signaled that his or her entry costs would be unrecoverable (Cramton-Stoft, 2007).

The method by which individual plants and firms dispatch to gain short-run profit directly translates to the aggregate electricity market. To illustrate, consider an individual power plant possessing any variety of generation technology. This plant, regardless of type, will be willing to produce up to its capacity whenever the market's clearing price is above its hourly marginal cost, generating short-run profit necessary to recover long-run fixed costs (Murray, 2009). Accordingly, individual plants exhibit a flat short-run supply curve $S_p(Q)$ at their marginal cost, as illustrated in Figure 3.

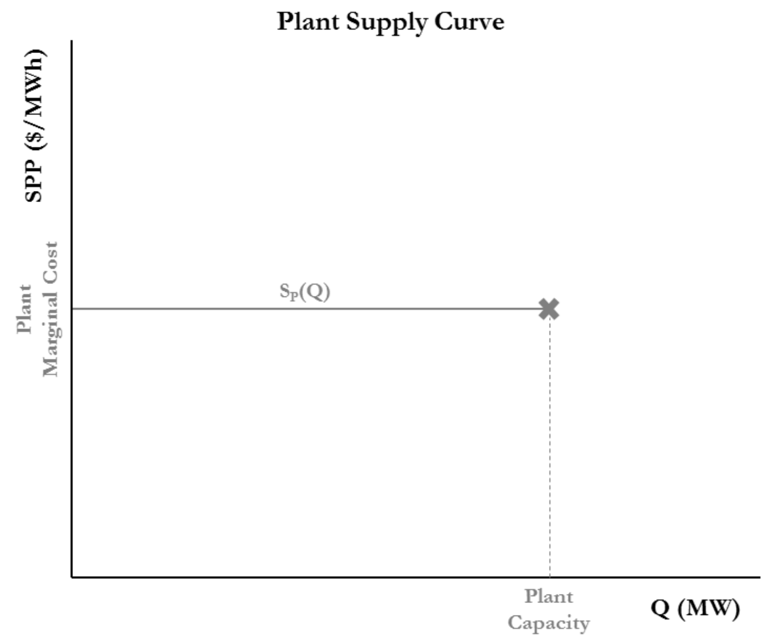

Figure 3: A hypothetical plant's supply curve.

Any firm of reasonable scale will possess multiple plants of varying short-run efficiency. The rational firm is willing to produce from any of its plants at full capacity so long as the market price is greater than the plant's individual marginal cost. Ordering the dispatch of a firm's production units by efficiency, a hypothetical firm's supply curve might then appear something like $S_F(Q)$ in Figure 4. Firms are price-takers in this market; they submit a supply schedule of quantities they are willing to produce at various prices based on the marginal costs of their generation assets. For example, the hypothetical firm in Figure 4 would be willing to produce Q_1 at a market clearing price of SPP_1[14] by dispatching its nuclear and combined cycle plants. However, in the event that market prices rise to SPP_2, the same

[14] I use SPP (Settlement Point Price) as the market clearing price to remain consistent with ERCOT nomenclature regarding firm decision prices.

firm would additionally dispatch its single-cycle, coal-fired, and oil-fired plants that operate with marginal operating costs less than the new prevailing market price.

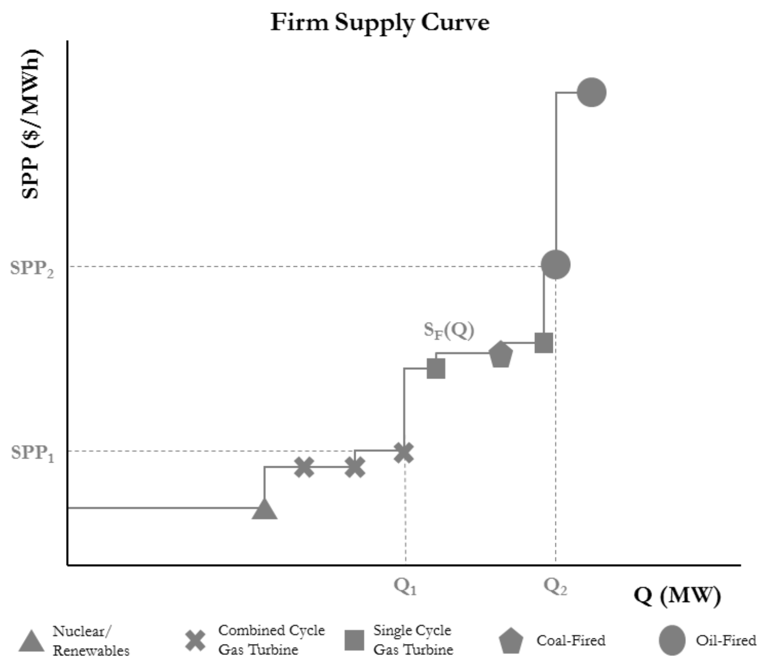

Figure 4: A hypothetical firm's supply curve.

A market operator such as ERCOT then aggregates all of the firm's supply schedules and dispatches a market's plants in order of decreasing efficiency. This creates the market's aggregate supply curve, which is also referred to as the generation stack or supply stack. The supply stack represents the entire supply available to the market at any given point and encompasses all generation assets in a given region.[15] $S_M(Q)$ in Figure 5 serves as a visual representation of this curve and provides reference for the relative efficiency of major

[15] An actual electricity market will split its entire service area into many different operating nodes, calculating individual supply and demand curves for each. The market operator then makes use of long-distance electricity transmission to account for nodal supply-demand imbalances and calculates an aggregate least-cost dispatch.

generation technologies. $S_M(Q)$ is fixed in the short-run to reflect the market's barriers to entry.

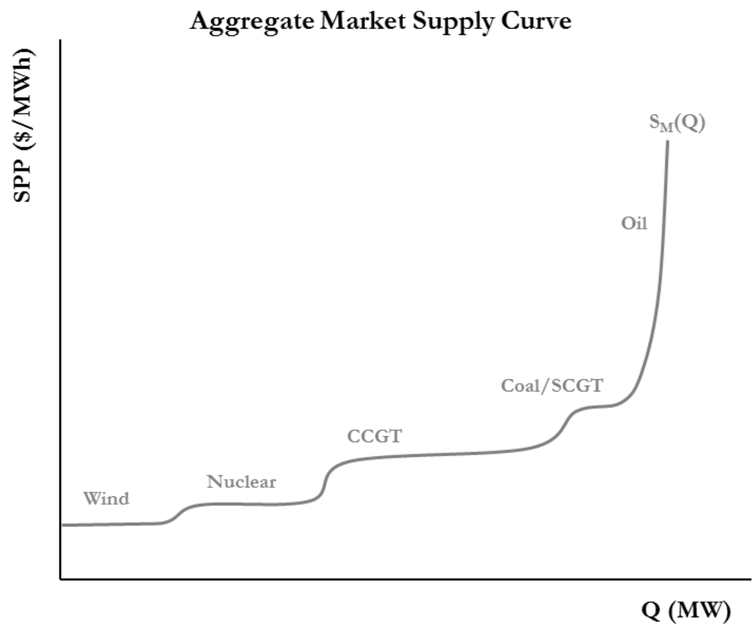

Figure 5: A hypothetical market's aggregate supply curve.

Short-run market demand, represented in Figure 6 as $D_M(Q)$, is nearly perfectly inelastic and shifts based on the quantity of electricity demanded by market consumers (Stoft, 2002).[16,17] Fixed short-run supply and inelastic short-run demand imply that price is dictated primarily by the quantity of electricity demanded and the corresponding least-cost dispatch which will produce said quantity. Following the law of one price, all power plants receive the

[16] This represents a major simplification of actual electricity market mechanisms, but it is sufficient for the purposes of this paper. In reality, over 90% of power is sold in advance through bilateral contracts, with the real-time spot market providing last minute balancing adjustments (Hortacsu-Puller, 2007). However, bilateral contracts reflect spot prices in the long-run and the real-time market still follows the dispatch characteristics described herein.

[17] Market demand is close to perfectly inelastic in the short-run because few consumers currently have the ability to detect and respond to changes in electricity prices (Murray, 2009). Smart home thermostats and demand-response initiatives are attempting to change this dynamic, but electricity prices are still primarily determined by the quantity demanded and the corresponding cost of producing that amount of electricity.

clearing price of electricity regardless of their marginal cost, providing short-run profit for all plants with higher operating efficiency than the marginally dispatched plant.

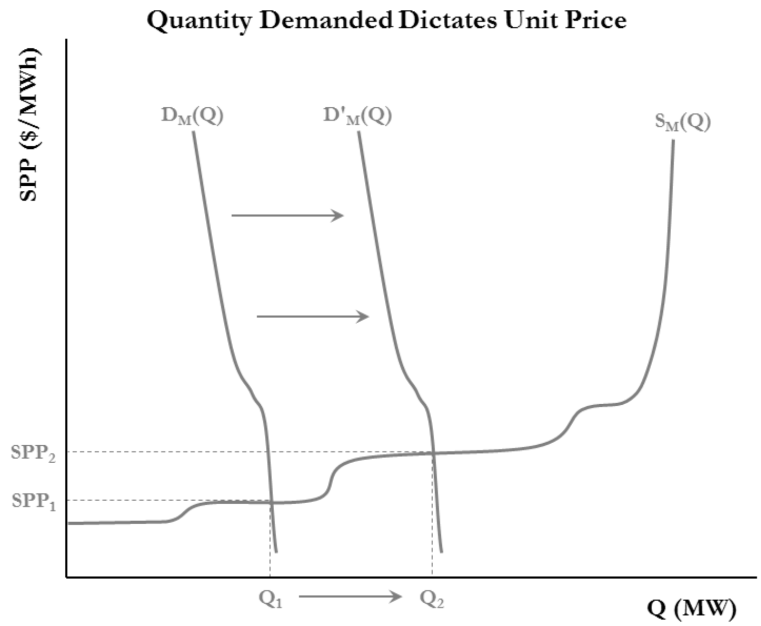

Figure 6: The interaction of aggregate demand with aggregate supply.

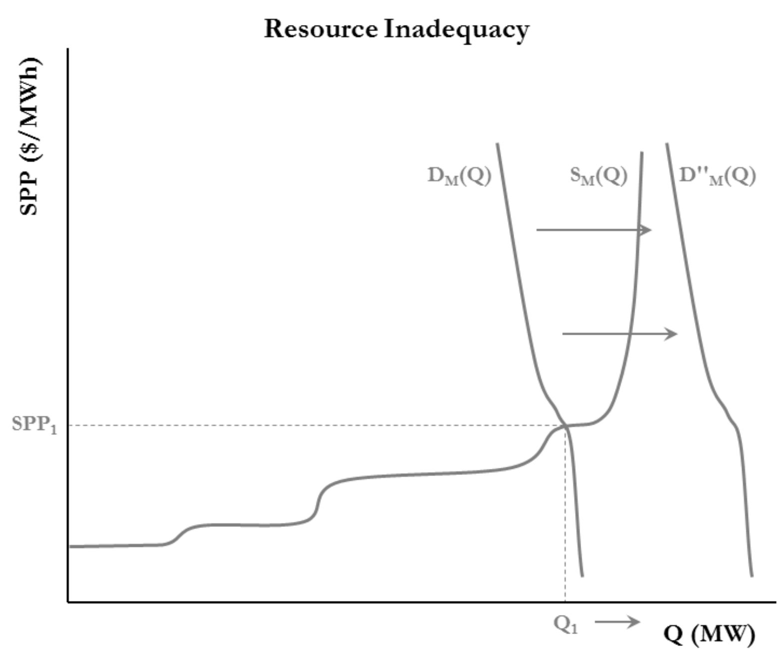

Figure 7: An example of a demand spike creating a load-shed event.

As $D_M(Q)$ shifts to $D'_M(Q)$ in Figure 6, the market dispatches additional power plants to meet the increased demanded quantity Q_2, which raises the clearing price to the new marginal plant's variable cost, SPP_2. Problems occur when short-term demands spikes, usually resultant from extreme weather events, shift $D_M(Q)$ to the point where the required quantity of electricity exceeds supply available to the system. This phenomenon is showcased in Figure 7. As $D_M(Q)$ shifts to $D''_M(Q)$, the market operator eventually runs out of new units to dispatch, causing rotational load shedding or a complete grid failure.[18] Even if a positive demand shift does not cause shedding, it always pushes demand into a steeper part of the supply stack, leading to a higher clearing price.

Economic theory teaches us that markets such as the one described above deliver efficiency without administrative intervention, however an efficient electricity market would likely leave many consumers outraged. Electricity has no inventory, meaning that supply and demand must meet at every second of the day to avoid load-shedding. An efficient electricity market would incentivize enough capacity investment to meet demand "in equilibrium," but the multitude of factors[19] constantly affecting power markets prevents the existence of any sustained short-run equilibrium (Stoft, 2002). Even if an efficient market were able to ensure sufficient market capacity to cover 95% of peak demand, no consumer or regulatory body would be satisfied with involuntary electricity curtailment during 5% of operating hours.

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[18] This is, again, a simplification. There are many complex causes for outages and price spikes including but not limited to grid congestion, weather events, demand shocks, plant outages, and transmission failures. However, the major load-shedding events which are indicative of resource inadequacy in ERCOT have historically resulted from extreme weather (Anderson, 2014).

[19] These factors include but are not limited to varying seasonal and intra-day demand, shifting locational load-profiles, and changing input prices.

The reliability of a market is therefore of the utmost importance to a service area's retail electricity customers. Reliability is the market's ability to consistently generate and transmit power without shedding load; as an example, ERCOT's current reliability target is to experience one load-shed event every 10 years (Newell, 2012). In order to ensure reliability, the market operator must provide short-term revenues in excess of those naturally present in an efficient market, inducing investment beyond theoretically efficient levels. Resource adequacy programs aim to solve this problem by increasing generation revenues, boosting short-term profits to support an investment level above that produced by efficient market prices.

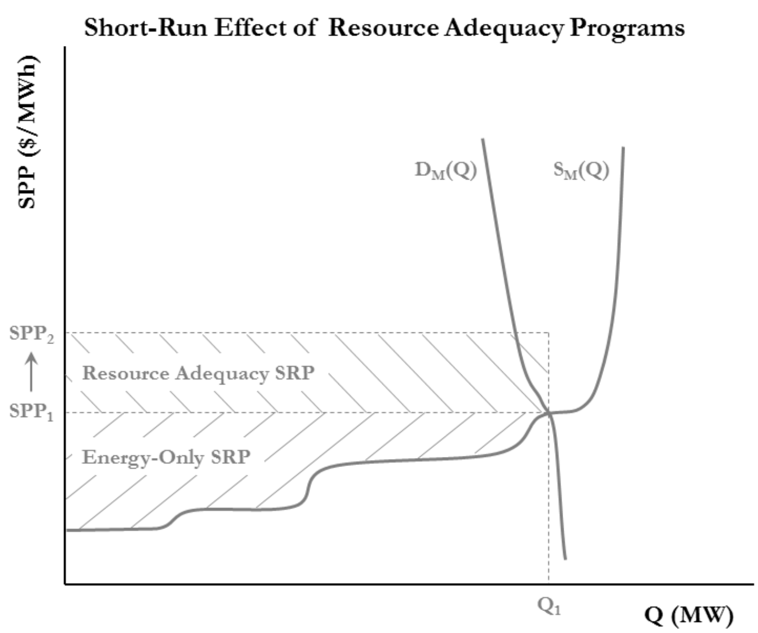

Figure 8: The short-run effect of resource adequacy proposals is to the raise producer revenues in support of heightened capacity investment.

Figure 8 illustrates the short-run effect of a hypothetical resource adequacy program, boosting the market's clearing price above the intersection of supply and demand (from

SPP_1 to SPP_2) to generate additional short-run profit (SRP) for power generators. ERCOT's ORDC does this in real-time by constructing a price-adder to artificially raise the market price of electricity. Alternatively, capacity auctions such as those implemented in PJM provide generators with an annual lump-sum payment. While the delivery method and administrative parameters differ for each program, the end goal is the same: secure new investment by providing a higher level of fixed-cost recovery.

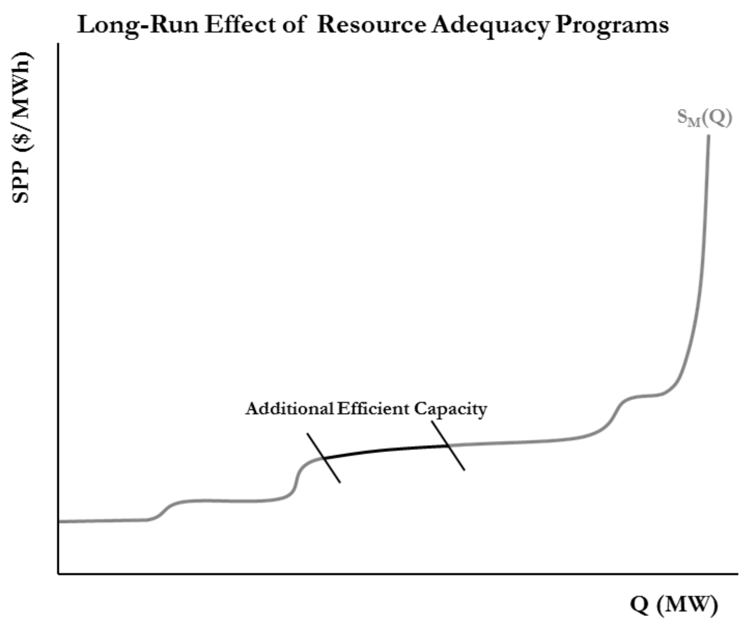

Figure 9: Increased investment in cost-efficient capacity flattens the market's supply curve and reduces the probability of load-shed events (Cramton-Stoft, 2006).

The increase in short-run profit provided by resource adequacy programs translates to an increased willingness for market entry on the part of investors (Stoft, 2002; Newell, 2012; Plewes, 2013). Figure 9 shows the manner in which resultant new investment in efficient capacity elongates and flattens the market's supply curve. The addition of marginal plants from increased investment therefore lessens the likelihood of load-shedding by providing incremental system capacity. In addition, it lowers the generation-weighted average cost of electricity by reducing the frequency of shortage conditions, which lead to price spikes.

When evaluating market entry, one generally seeks to determine whether or not a prospective plant's energy and resource adequacy revenues combine to make an investment profitable (Plewes, 2013; Newell, 2014). The helpfulness of the resource adequacy program itself is therefore determined by its ability to bridge the gap between existing net revenues and expected entry costs.

IV.ii. Electricity Pricing

From Equation 2,[20] the real-time settlement point price ($RTSPP$) paid to generation resources is made up of two primary components, the baseline locational marginal price ($RTLMP$) and the ORDC revenue addition ($RTORPA$). While ORDC revenue additions are identical throughout ERCOT's electricity spot market, the underlying $RTLMP$'s vary by location to account for factors such as varying load, transmission congestion, and day-ahead market orders. While the construction of the $RTORPA$ is explained in Section IV.iii., this segment is intended to provide intuition for the process behind the derivation of the baseline energy price, referred to hereafter exclusively as $RTLMP$.

Drawing from the Section IV.i., the $RTLMP$ can be thought of as the energy-only price of electricity resultant from the intersection of market supply and demand (SPP_1 in Figure 8). ERCOT launched a nodal wholesale market design in December 2010, meaning

[20] For convenience, Equation 2 is $RTSPP = RTLMP + RTORPA$, meaning that the real-time settlement point is the sum of the real-time locational marginal price and the real-time online reserve price adder (ORDC price adder).

that the market is broken up into hundreds of geographic nodes, each of which is assigned a nodal (locational) marginal price, the $RTLMP$ (ERCOT, 2014).

The $RTLMP$ is calculated via a process which ERCOT terms Security Constrained Economic Dispatch (SCED). SCED calculates separate supply and demand curves at each node before minimizing the generation-weighted average electricity price across the system by using ERCOT's transmission system to account for nodal supply-demand imbalances (ERCOT, 2014). In other words, if electricity would cost \$20/MWh at Node A, and \$30/MWh at Node B, SCED would transmit electricity from Node A to Node B until the total system cost was minimized. Because there is real cost to the transmission of electricity, the resultant prices *will not* be uniform across ERCOT's entire region, but they *will* minimize ERCOT's total system cost of electricity, providing competitive electricity prices at each node.

The SCED process repeats every 5 minutes, with the results averaged within each fifteen-minute settlement period to calculate the $RTLMP$ that represents the first component of the $RTSPP$.

IV.iii. ORDC Construction

The second component of the $RTSPP$ is the ORDC's real-time online reserve price adder ($RTORPA$). During any given settlement period, the $RTORPA$ itself is uniform at every node in ERCOT, meaning that its effect can be evaluated on a system-wide basis. The ORDC's price adder assigns value to peaking capacity by raising the real-time electricity price when the level of real-time reserves available to ERCOT becomes too low. This policy aims to attain long-run target capacity reserve margins by increasing the value of real-time system reserves, contending that the long-term is simply a succession of many separate short-term markets (Hogan, 2012). Other economists challenge this contention by asserting that markets inherently possess no concept of reliability, and thus the ORDC cannot provide economic incentive to achieve a reliable level of capacity unless administratively parameterized to do so (Cramton-Stoft, 2006). They claim that this represents administrative interference on par with a capacity market, while providing less clarity and higher levels of risk.

ERCOT's nodal protocols and ORDC mechanics whitepaper detail the actual calculations behind the ORDC's implementation in Texas. The ORDC's practical mechanics rely heavily on two primary parameters: the value of lost load (VOLL) and the loss of load probability (LOLP) (ERCOT, 2014; ERCOT, 2015).

The value of lost load (VOLL) is input as an administratively set value representative of the total system cost from a load-shedding event. This value is notoriously hard to determine and remains a subject of debate amongst economists focused on electricity market design (Stoft, 2002; Cramton-Stoft, 2007; Murray, 2009). In the case of ERCOT's chosen ORDC from Figure 2, VOLL would be held constant at 9,000.[21] The loss of load probability (LOLP) is then calculated by analyzing historical data on the probability of load loss from various real-time reserve margin levels.

[21] The ORDC's VOLL was set at $7,000 over the course of this study period and will be raised to $9,000 in the summer of 2015. This increase will translate to more ORDC revenue, but this increase will be proportional to the difference between 7,000 and 9,000, rather than increasing by any order of magnitude. As a result, this increase will not change the results found in this study.

ERCOT then places reserves into two categories. The first is "immediate" or "spinning" reserves, which promise to be available at any time should they be dispatched. The second category is "thirty-minute" or "non-spinning" reserves, which promise availability within thirty minutes of a dispatch notification. Calculating the spinning reserve price adder ($RTORPA$) and non-spinning reserve price adder ($RTOFFPA$) is accomplished via the following equations:

$$RTORPA = v * 0.5 * LOLP_S(R_S) + P_{NS} \tag{3}$$

$$RTOFFPA = v * (1 - 0.5) * LOLP_{NS}(R_{NS}) \tag{4}$$

Where v is the net value of load curtailment,[22] $LOLP_S$ is the loss of load probability for immediate reserves, and $LOLP_{NS}$ is the loss of load probability for thirty-minute reserves. R_S is then the current level of spinning reserves and R_{NS} is the current level of non-spinning reserves. Solving these equations for $RTORPA$ and $RTOFFPA$ determines the new reserve prices which are intended to adequately incentivize supply bidding into the reserve market, as necessitated by the amount of real-time reserves available prior to any dispatch interval (ERCOT, 2015).

This subsection evidences the lack of intuition inherent in the ORDC's complex derivation. The ORDC is often criticized for relying on administratively set parameters such as the value of lost load and esoteric ones such as the loss of load probability. It is therefore generally unclear to the average investor what value the ORDC's price adder actually represents, and how they can estimate the degree to which their prospective plant could

[22] Net value of load curtailment is calculated as VOLL minus what is known as the "system lambda." System lambda is subtracted from VOLL to reflect the scarcity value of the marginal dispatch capacity and to ensure that the final cost of energy does not go above the VOLL (ERCOT, 2014).

provide that value. After construction, the ORDC's revenue additions are embedded into the real-time settlement point prices ($RTSPP$'s) provided to resource nodes for dispatch decisions, further clouding the curve's separable effect for producers.

The Brattle Group's 2012 assessment of ERCOT's resource adequacy noted that the ORDC's implementation was advantageous only in the sense that the curve could increase prices to close the gap between producer net revenues and annual fixed costs, achieving target reliability "in expectation" when correctly parameterized. However, the study noted that the ORDC did not guarantee reliability and that the use of price adders introduced inefficiencies into the real-time market (Newell, 2012).

IV.iv. Capacity Market Alternative

The primary alternative to the ORDC for achieving resource adequacy is known as a capacity market, in which a system operator (in this case ERCOT[23]) pays producers to construct new capacity several years in advance. While implementation differs between service areas, the fundamental economic theory behind every region's capacity auction process is the same. During a capacity auction, the grid operator will determine how much additional capacity the service region will need three years from the auction date in order to meet its target reserve margin. The operator then sets this incremental capacity requirement as a fixed parameter in the auction. The capacity price determined by the auction is therefore representative of the guaranteed annual revenue (separate from the market's projected net energy revenues) an investor would require in order to be willing to construct new capacity

[23] ERCOT does not have an installed capacity market, this exercise is hypothetical. In fact, ERCOT is currently the only restructured market which does not use capacity auctions (Anderson, 2014).

(ISO-NE, 2014). Following the logic from earlier subsections, this annual lump-sum capacity payment will be representative of the investor's expected difference between projected energy revenues and projected fixed costs (Stoft, 2002).

Potential market investors submit bids to the auction which are representative of their own estimate of the annual lump-sum payment they would need in order to recover their fixed costs of construction. The auction then procures capacity in order of increasing cost until the target amount of new capacity is met. This process is illustrated below in Figure 10. Regardless of the bids submitted by investors, the auction will demand and receive new installed capacity (ICAP) of Q_1. The capacity price is then determined by the nature of bids submitted by potential investors. For example, if suppliers submitted bids to build plants that created the installed capacity supply curve $S_{ICAP}(Q)$, the market operator would request construction of Q_1 megawatts of capacity and pay all of those investors P_1 per megawatt every year for a certain guaranteed period.[24]

[24] Typically 3-5 years.

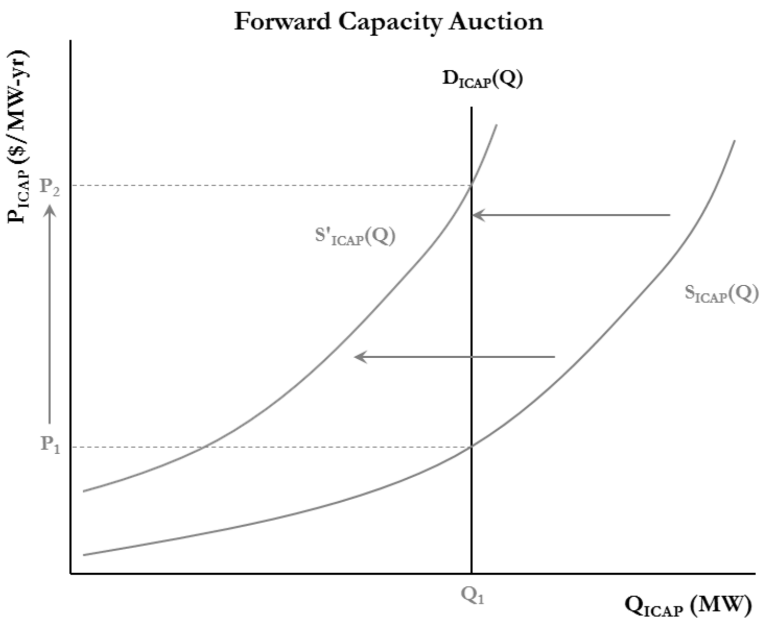

Figure 10: A capacity auction guarantees that a market will acquire a specific level of capacity necessary to provide reliability. It compensates investors with an annual lump-sum payment (ISO-NE, 2015).

In the event of a market downturn such as the one experienced in ERCOT since 2008, a producer's energy net revenues are significantly lowered. This widens the gap between an investor's projected fixed costs and projected energy revenues, which means that they require a larger annual lump-sum payment to construct new capacity. Capacity markets handle this scenario fluidly as illustrated in Figure 10. Lower projected revenue would cause investors to raise their installed capacity supply bids, shifting the supply curve from $S_{ICAP}(Q)$ to $S'_{ICAP}(Q)$. As a result, the installed capacity market's price would rise from P_1 to P_2, bridging the now larger gap between the producer's projected fixed costs and projected net revenues.

Following the law of one price, all of a system's power plants are paid the same capacity price for their installed capacity, regardless of age.[25] This ensures that the market procures the cheapest possible form of incremental capacity, valuing incremental capacity additions to existing plants at the same price that it would value an entirely new plant (Cramton-Stoft, 2006). The market design described above also provides producers with relative assurance that their investment is protected from unpredictable market forces, because deteriorating market conditions would boost installed capacity revenues, thereby providing investors with a relatively assured fixed cost recovery (ISO-NE, 2014).

The Brattle Group's (2012) study on ERCOT's resource adequacy noted that "implementing a capacity market [in ERCOT] would reduce the risks associated with potential low-reliability and high-cost events, providing net benefits overall from a risk-averse (rather than risk-neutral) perspective." The economic consultant went on to note that the forward capacity market provided investors with transparent prices and guaranteed reserve margin levels. The only tangible negative the study cited of a capacity market in ERCOT was that the market's implementation would require a major market redesign with many administrative determinations. The study further noted that ERCOT seemed to lack the political will to implement such a market, citing the idea's unpopularity among the PUCT's members (Newell, 2012).

The difference in clarity between the ORDC and a potential capacity market is evident from the descriptions of each which are contained in this section. In addition to the

[25] The exception to this rule is ISO-NE, which is currently experimenting with separate "new" and "existing" capacity prices.

Brattle Group, both Charles River Associates and Potomac Economics have previously advocated for ERCOT's creation of a capacity market to assist failing generators in meeting their capital and fixed cost obligations (Plewes, 2013; Potomac, 2014).

V. Data

The data necessary to undertake a system-wide analysis of ERCOT's ORDC fall into three primary categories: (1) market data on ERCOT electricity and scarcity pricing, (2) market data on natural gas input prices, and (3) cost and efficiency estimates for the "characteristic" gas plants which an investor might build in ERCOT.

I obtained system-wide ERCOT market data (1) via two separate information retrieval processes: first for ORDC data ($RTORPA$) and second for settlement point price ($RTSPP$) data. ORDC data are readily available on ERCOT's website[26] and are stored within the Historical Real-Time Reserve ORDC Price Adder report. I downloaded and aggregated these data for the period under study; an example of these data from October 1, 2014 is shown below:

	Price Adders	
Timestamp	RTORPA	RTOFFPA
10/01/2014 00:00:17	0.0000	0.0000
10/01/2014 00:00:17	0.0000	0.0000
10/01/2014 00:10:08	0.0000	0.0000
10/01/2014 00:15:09	0.0000	0.0000
10/01/2014 00:20:08	0.0000	0.0000
…	…	…
10/01/2014 12:55:08	0.0103	0.0166
10/01/2014 13:00:17	0.0115	0.0015
10/01/2014 13:00:17	0.0119	0.0016
10/01/2014 13:10:07	0.0166	0.0020

Table 2: Historical Real-Time Reserve Price Adder on October 1, 2014 (ERCOT, 2014).

[26] http://www.ercot.com/mktinfo/rtm/index.html

These data show that the price adders represented by $RTORPA$ and $RTOFFPA$ were held constant at zero during the low-demand hours near midnight on the first of October, 2014. As the system neared peak demand during early-afternoon hours, the price adders increase to assign higher value to system reserves. My analysis utilizes the $RTORPA$, or the on-line price adder, because it is added to the $RTLMP$ in order to form the $RTSPP$ generators use to make dispatch decisions (ERCOT, 2015).

The $RTORPA$ data are measured in dollars per megawatt-hour and their distribution has a mean of 0.183 and a median of 0.000. In fact, the real-time price adder is equal to 0 (such that it is adding nothing to the system) during 80.3% of all intervals under study. Similarly, the $RTORPA$ is less than 10 $\$/$MWh in 99.6% of all intervals. The high proportion of zero intervals, coupled with the fact that the adder cannot take on a negative value, implies that the distribution of adders must have a strong rightward skew in order to add any reasonably significant value to the system. This notion is correct: the adder's highest value over its first six months of implementation was 304.337 $\$/$MWh, and the standard deviation of the distribution is 2.703 $\$/$MWh. Despite 99.6% of all adder values being less than 10 $\$/$MWh, the other 0.4% of occurrences account for 67.4% of the total value added by the ORDC. Figure 11 shows the frequency of adder counts while Figure 12 displays their sum. The fact that such a high percentage of revenues come from such a small number of occurrences is an early but accurate indicator that the ORDC's revenue is highly variable and unpredictable.

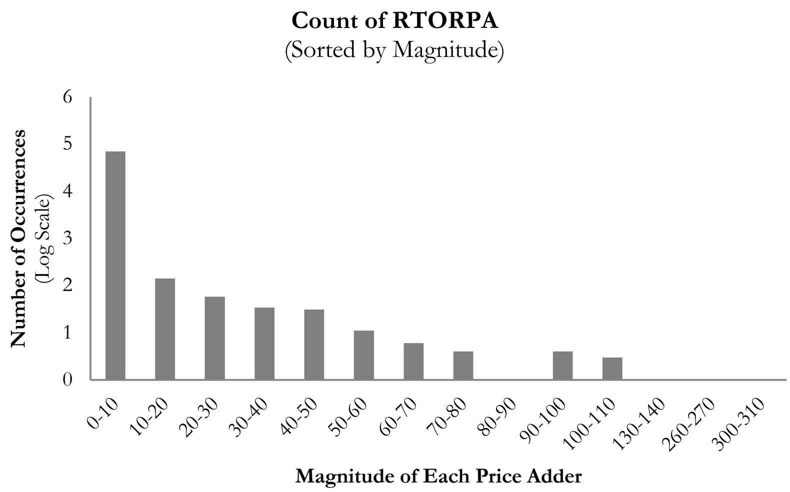

Figure 11: Frequency distribution of scarcity adder counts organized by magnitude from June 1, 2014 to January 31, 2015 (ERCOT, 2014; ERCOT, 2015).

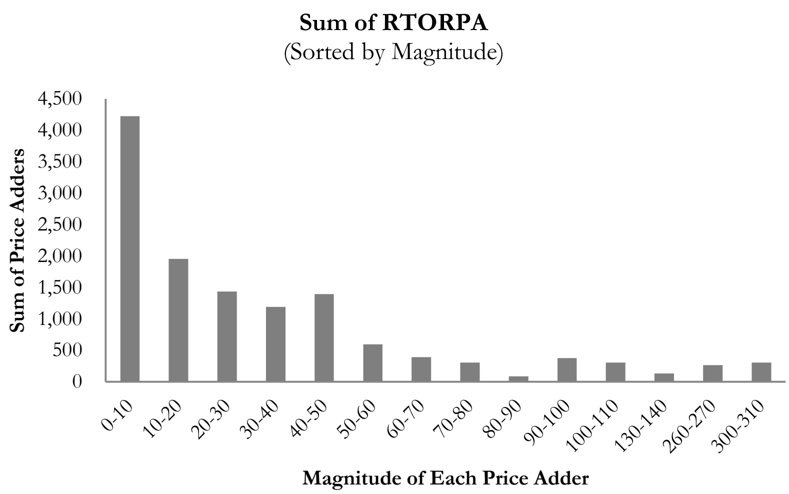

Figure 12: Sum of scarcity adders organized by magnitude from June 1, 2014 to January 31, 2015 (ERCOT, 2014; ERCOT, 2015).

Attaining and aggregating price data for $RTSPP$'s was significantly more difficult than for the price adder itself. I received roughly 80,000 files from ERCOT, with each file representative of a single dispatch interval's nodal prices. I used a python script to scrape and aggregate this data into a form usable by my model. For reproducibility, this script is included in Appendix E.

For data on natural gas input prices (2), I utilized historical Bloomberg data sets for Henry Hub and Houston Shipping Channel prices over the course of the study period. I averaged daily closing price data by month to arrive at a monthly gas price which was then used for dispatch logic and fuel cost calculations (Bloomberg, 2015).

For cost and efficiency estimates of a "characteristic" plant (3), I primarily drew from Newell's (2014) report on optimal reserve margins in ERCOT. This report provides up-to-date, ERCOT-specific estimates for key features of hypothetical new marginal plants which I use in my analysis. Table 3 below represents a subset of these characteristics:

		Plant Type	
		Single Cycle	Combined Cycle
Plant Configuration			
Turbine		GE 7FA.05	GE 7FA.05
Configuration		2 x 0	2 x 1
Heat Rate			
Non-Summer	*(btu/kWh)*	10,094	6,722
Summer	*(btu/kWh)*	10,320	6,883
Installed Capacity			
Non-Summer	*(MW)*	418	627
Summer	*(MW)*	390	584

Table 3: Estimated performance characteristics of hypothetical reference marginal plants in ERCOT (Newell, 2014).

The two most important operational characteristics which one must learn about a hypothetical plant are its capacity and heat rate. The plant's capacity is another word for its size; it tells us the amount of power the plant will be able to sell into the market at any given time and is generally correlated with the amount of fixed costs for any given power plant.

Separately, a heat rate tells us how efficiently the plant can turn natural gas into electric power. This information is important primarily to determine plant dispatch. I sensitize my analysis of the ORDC across both of the single cycle and combined cycle peaking plants[27] characterized in Table 3.

I additionally draw information on annualized cost of market entry from Newell's (2014) report on optimal reserve margin, which is presented below in Table 4. Information on further assumptions utilized in this study can be found in Appendix B.

	Gross Cost of New Entry	
	Single *($/kW-yr)*	Combined *($/kW-yr)*
Brattle Group Estimate		
Low: Base minus 10%	$87.30	$109.89
Base: Merchant ATWACC	$97.00	$122.10
High: Base plus 25%	$121.25	$152.63

Table 4: Gross cost of new entry estimates for hypothetical new marginal plants in ERCOT (Newell, 2014).

[27] Single cycle and combined cycle natural gas plants are both examples of hypothetical new plants which could be on the margin during peak hours. Single-cycle plants have lower fixed costs but are less efficient and therefore run less frequently.

VI. Empirical Specification

VI.i. ORDC Revenue Additions

The most fundamental evaluating factor in determining the effectiveness of the Operating Reserve Demand Curve will be the incremental net revenue it generates for market participants in ERCOT. These revenue additions[28] will be the subject of much scrutiny from investors attempting to discern whether or not an entry into the ERCOT market will be profitable. In order for the ORDC to be successful in ameliorating ERCOT's resource adequacy problem, it must create enough short-run profit to bridge the gap between existing energy-only net revenues and a firm's fixed-cost of new entry.

The real-time online reserve price adder ($RTORPA$), which sets the price for on-line reserves in excess of real-time locational marginal prices ($RTLMP$'s), is paid out to all market participants providing either on-line reserves or electricity to ERCOT. This treats real-time energy market and reserve market participation as equivalent and ensures that producers are indifferent between offering either of the two services. According to ERCOT training materials and nodal protocols, each $RTORPA$ is time-weighted within its 15-minute dispatch interval before being added to the locational marginal price of electricity in the spot market (ERCOT, 2014). Equation 3 below specifies the process by which the price adders are averaged.

$$ORDC\ Price\ Addition = \sum_y \left(RTORPA_y * \frac{TLMP_y}{\sum_y TLMP_y} \right) \tag{5}$$

[28] ORDC Revenue Additions represent additional top-line revenue that a power plant will receive due to the implementation of the ORDC. These revenue additions are resultant from the ORDC's price adders increasing the spot price of electricity sold by the plant.

$TLMP_y$ in Equation 5 represents the duration of the dispatch interval at time y, meaning that $\frac{TLMP_y}{\sum_y TLMP_y}$ provides a relative time-weighting for the y^{th} interval relative to the other intervals within the current dispatch period. The y^{th} time-weighting factor is then multiplied by the online reserve price adder itself ($RTORPA$), to arrive at the ORDC price addition for that single dispatch (SCED[29]) interval. The time-weighted price additions are then summed across all dispatch intervals for the settlement period in question (generally 15 minutes) and added to the spot price of electricity ($RTLMP$) over the same period. This provides the final price of electricity ($RTSPP$) received by power producers in ERCOT's market.

I treat the ORDC's price addition as additively separable from the remainder of the electricity price.[30] Therefore, I compute the total ORDC revenue additions to ERCOT's real-time market by summing across the time-weighted RTORPA adders from June 1, 2014 to January 31, 2015. This time-weighted summation provides the total resource adequacy producer surplus generated by the ORDC on a per-unit generation basis. In practical terms, this analysis tells me how much additional revenue a power plant would get, were it to be constantly operating year-round.[31] While continuous operation is not a realistic assumption, aggregate ORDC revenues contribute perspective regarding the magnitude of the curve's effect on the system as a whole. The magnitude of total revenues additionally allow me to

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[29] SCED stands for Security Constrained Economic Dispatch. An overview of this mechanism is provided in Section IV: Electricity Pricing.

[30] A full derivation of additive separability can be found in Appendix A.

[31] This is not a realistic assumption in practicality because plants only dispatch when economically incentivized to do so. Further, plants only receive electricity revenues and therefore revenue additions for the periods in which they are operating and generating electricity. Accordingly, my primary analysis employs an economic dispatch model.

later determine the percentage of $RTORPA$ adders that are actually being captured by plants operating under economic dispatch assumptions. In Section VI.ii., I discuss the economic dispatch model I employed to determine realistic operating characteristics for reference technologies over the study period.

VI.ii. Economic Plant Dispatch

In order to more accurately determine the contextual effect of the operating reserve demand curve on power plant energy margins and generation investment, I develop an economic model of plant dispatch which determines a hypothetical reference plant's net revenues based on projected hours of operation, gross revenues, and variable costs. My version of this model has been modified to separate ORDC revenue contributions in order to better understand the curve's role in a plant's operating profile. This model for determining dispatch is consistent with models used by Potomac Economics,[32] the Brattle Group,[33] and Charles River Associates[34] in assessing a plant's level of fixed cost recovery (Potomac, 2014; Newell, 2012; Plewes, 2013). The model's main shortcoming is that it does not account for ancillary service revenues; however, these revenues have historically amounted to less than 5% of total gas plant net revenues in ERCOT, which is not of sufficient magnitude to affect the conclusions of this study (Plewes, 2013).

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[32] Potomac Economics is the Independent Market Monitor tasked with compiling ERCOT's annual state of the market report.
[33] The Brattle Group is an independent economic consultant commissioned by the PUCT to assess ERCOT's resource adequacy programs.
[34] Charles River Associates is an independent economic consultant which was commissioned by NRG Energy to produce a study on ERCOT's resource adequacy problems.

My analysis of hypothetical marginal plants was tested across a variety of possible parameters including plant location, chosen resource technology, natural gas hub, plant start-up cost, and variable operating and maintenance costs. The dispatch model itself takes into account complexities such as plant dispatch optimization, start-up cost incorporation, and ORDC revenue separation. A full description of model parameters can be found in Appendix B; calculations used in the model's dispatch logic can be found in Appendix C; detailed descriptions of the various settlement points employed in the model can be found in Appendix D; examples of plant monthly statements of operations can be found in Appendix F. The model itself is also available upon request.[35]

[35] Please contact max.lipscomb@duke.edu for more information.

VII. Results

As discussed in this study's theoretical framework, the purpose of a market's resource adequacy (RA) program is to bridge the gap between a firm's projected net energy revenues and its expected cost of entry whenever the system contains supply below its target reserve margin (Stoft, 2002). This boosts producer surplus to incentivize a level of investment necessary to deliver market reliability. Accordingly, a successful resource adequacy program will demonstrate to investors that it has the capability of doing so not only in any given year, but also consistently over a longer period. Clear and consistent RA revenues of sufficient magnitude encourage market entry by signaling to the investor that fixed cost recovery is probable over a power plant's investment horizon (Cramton-Stoft, 2007). Therefore, in considering my empirical results from the ORDC's first eight months of implementation, I evaluate the program's clarity, consistency, and magnitude to determine the curve's overall effect on ERCOT's resource adequacy.[36]

To begin, I gauged the curve's net revenue additions on an absolute basis without accounting for firm dispatch. From June 1, 2014 to January 31, 2015, the ORDC's price adder ($RTORPA$) added \$1.08 per kW in gross revenue to any power plant that was in constant operation. On an annualized basis, this represents a \$1.61 per kW-yr revenue increase for ERCOT wholesale market participants.[37] To contextualize this result, I compare

[36] Throughout this discussion, I annualize absolute dollar amounts by multiplying by the number of days in a year and dividing by the number of days for which data was collected.
[37] As mentioned in Section VI, constant operation is not a realistic assumption in practicality because plants only dispatch when economically incentivized to do so. Accordingly, my primary analysis employs an economic dispatch model.

it to annualized fixed cost estimates from the Brattle Group and Potomac Economics.[38] This comparison is displayed in Table 5. The ORDC's net revenue increase only covers 1.3% to 1.7% of a generator's annual fixed costs over the course of the study period, meaning that even if a prospective plant were to be in constant operation, it would only recover a meager portion of its fixed costs from the ORDC's resource adequacy revenues.

	Realized *Jun. '14-Jan. '15*	Projected *Annualized*
Net Revenue Addition ($/kW-yr)	$1.08	$1.61
SCGT Estimated CONE ($/kW-yr)		
Brattle Group Base Estimate		$97.00
ORDC % Coverage		*1.7%*
Potomac Economics Base Estimate		$92.50
ORDC % Coverage		*1.7%*
CCGT Estimated CONE ($/kW-yr)		
Brattle Group Base Estimate		$122.10
ORDC % Coverage		*1.3%*
Potomac Economics Base Estimate		$120.00
ORDC % Coverage		*1.3%*

Table 5: ORDC revenue addition on a dollar per kW-yr basis for hypothetical ERCOT plants. The revenue addition compared against expected annual fixed entry cost estimates from Potomac Economics and The Brattle Group.

Initially, this amount of fixed cost coverage appears to be almost negligible for generators in a previously revenue inadequate market. However, it is entirely possible that market conditions over the study period presented generators with a very small gap between energy net revenues and projected fixed costs, meaning that a ~1.5% increase in cost coverage sufficiently addresses resource adequacy concerns. In order to decisively evaluate

[38] Throughout this section, I use Brattle's base case CONE estimates of $97.00/kW-yr for SCGT plants and $122.10/kW-yr for CCGT plants. For Potomac Economics, I use the midpoint of their estimated CONE range, which is $92.50/kW-yr for SCGT plants and $120.00/kW-yr for CCGT plants.

whether or not the combination of energy and RA revenues met a generator's projected fixed costs over the course of the study period, I employ the economic dispatch model characterized in Section VI.ii.

In order to prove that the model's results are viable, I compared them against State of the Market (SOM) studies from 2012 and 2013 conducted by Potomac Economics, ERCOT's independent market monitor. The result of this comparison is displayed in Figure 13:

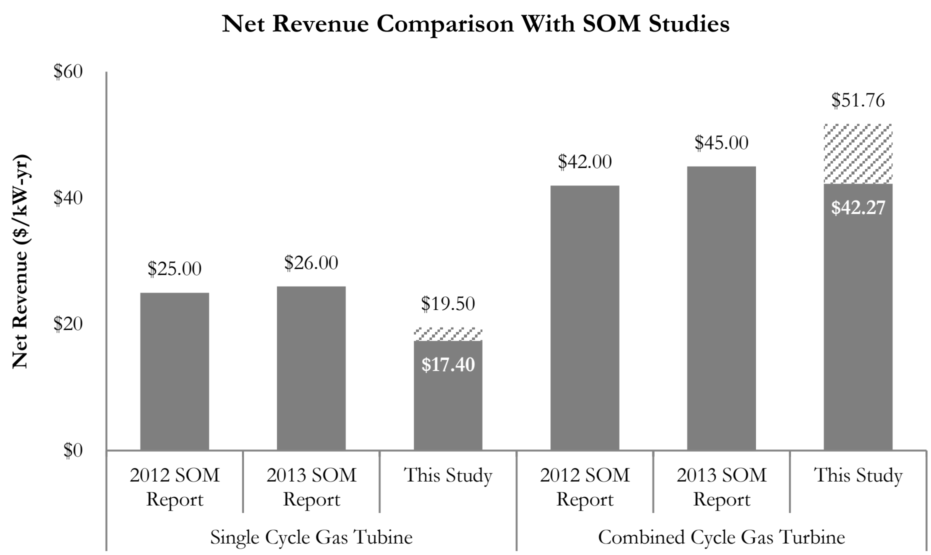

Figure 13: Comparison of producer net revenues calculated by this study with those from ERCOT's independent monitor in 2012 and 2013 (Potomac, 2013; Potomac, 2014).

Across all scenarios, this study's dispatch analysis yielded a range of combined cycle net revenues from $42.27 to $51.76 per kW-yr, compared with the SOM report's net revenues of $42.00 per kW-yr in 2012 and $45.00 per kW-yr in 2013. Similarly, I found that single cycle plants would have earned net revenues of $17.40 to $19.50 per kW-yr over the course of the study period, compared to SOM estimates of $25.00 per kW-yr and $26.00 per kW-yr for 2012 and 2013 respectively. While my single cycle net revenue range is slightly lower than Potomac Economics' 2012 and 2013 estimates, my results are generally comparable and in-line with the independent market monitor's findings. The period under study bore witness to a roughly 30% decrease in the price of natural gas, which would likely pressure energy margins of peaking plants based on ERCOT's 2008 market downturn (Optim, 2014; EFH, 2014). This at least partially explains the lowered net revenue range for single cycle plants. In addition, year-to-year net revenue differentials are expected given variety in weather conditions and electricity prices; these differentials may furthermore be resultant from methodological differences between my study and Potomac's. For example, I accounted for plant start up costs while the SOM reports did not, despite Potomac's note that they can be significant (Potomac, 2014). Similarly, Potomac calculated hypothetical ancillary service revenues while my analysis did not. Regardless, this comparison shows my study's results to be not only within the realm of believability, but also generally consistent with work done by industry professionals.

To provide descriptive statistics of my dispatch model's results, I performed uncertainty analysis on key performance indicators for hypothetical plants over the study period. The results of this analysis are summarized in Table 6. The table shows the full range of possible outcomes for each individual line item based on sensitivity analysis from all possible model scenarios. Because the dispatch model employs circular decision logic and because many of the most important dependent variables share indirect relationships, there is no singular best or worst case scenario. For example, an increase in the percentage of ORDC revenues captured would likely be resultant from an increased number of production hours, which would likely raise the plant's net revenues, lowering the ORDC's relative net revenue contribution. Therefore, each pair of low and high estimates represents the most extreme possible outcomes for that specific metric across all possible scenarios.

	Sensitivity Range	
	Low	High
Single Cycle Gas Turbine (SCGT)		
ORDC Revenue Captured ($/kW-yr)	$1.43	$1.52
ORDC Share of Gross Revenue (%)	*2.7%*	*3.3%*
Share of ORDC Rev. Captured (%)	*88.3%*	*93.7%*
Net Revenues ($/kW-yr)		
Dispatched Without ORDC	$16.05	$18.01
Dispatched With ORDC	$17.40	$19.50
% Improvement	*8.0%*	*9.1%*
Gross Cost of New Entry		
Net Revenue Coverage Without ORDC (%)	*16.5%*	*18.6%*
ORDC Coverage (%)	*1.0%*	*1.0%*
Net Revenue Coverage With ORDC (%)	*17.9%*	*20.1%*
Capacity Factor		
Without ORDC (%)	*7.1%*	*10.0%*
With ORDC (%)	*7.3%*	*10.2%*
Combined Cycle Gas Turbine (CCGT)		
ORDC Revenue Captured ($/kW-yr)	$1.55	$1.59
ORDC Share of Gross Revenue (%)	*0.9%*	*1.0%*
Share of ORDC Rev. Captured (%)	*95.4%*	*97.9%*
Net Revenues ($/kW-yr)		
Dispatched Without ORDC	$40.72	$50.17
Dispatched With ORDC	$42.27	$51.76
% Improvement	*3.2%*	*3.8%*
Gross Cost of New Entry		
Net Revenue Coverage Without ORDC (%)	*33.4%*	*41.1%*
ORDC Coverage (%)	*0.8%*	*0.9%*
Net Revenue Coverage With ORDC (%)	*34.6%*	*42.4%*
Capacity Factor		
Without ORDC (%)	*44.1%*	*55.4%*
With ORDC (%)	*44.1%*	*55.4%*

Table 6: Sensitized results from dispatch analysis of hypothetical reference plants in ERCOT. Varied assumptions for each reference technology include plant location, electricity price, and natural gas price. The Brattle Group's base case estimate was used across all scenarios for Gross Cost of New Entry comparison (Newell, 2014).

Over my hypothetical study period, a reference single cycle plant would have collected between 88.3% and 93.7% of the ORDC's total revenue while a combined cycle plant would have captured between 95.4% and 97.9%. Both reference technologies showed nearly identical capacity factors with and without the ORDC, indicating that the plants' dispatch profiles were not significantly altered. This finding is consistent with the curve's purpose: to provide additional revenues when system load is greatest and system resources are most scarce (i.e. when peaking plants are dispatched), thereby assigning value to the availability of those resources (Hogan, 2012). As intended, the curve is delivering the majority of its revenues during hours when peaking natural gas plants are online, correctly incentivizing the construction of least-cost generation capacity to ensure resource adequacy (Newell, 2014). While this demonstrates that ORDC revenues are being correctly targeted, their magnitude will be the deciding factor in any capital deployment assessment.

ORDC revenue represented roughly 1.0% of gross revenue[39] for combined cycle plants and 3.0% for single cycle plants over the course of the study period. This top-line increase trickled down through variable costs to boost net revenues roughly 3.5% for combined cycle plants and 8.5% for single cycle plants. Unfortunately, total net revenues inclusive of ORDC price additions still fell short of revenue adequate levels by a vast margin, failing to cover between 57% and 82% of a generator's fixed costs depending on scenario selection and plant turbine technology. A full scenario breakout of ERCOT's persistent revenue inadequacy is presented in Figure 14, which clearly shows that none of the scenarios examined in this analysis are remotely near to providing fixed cost recovery for ERCOT's

[39] Gross revenue is revenue prior to the subtraction of any variable costs.

peaking units. Charles River Associates' (CRA's) analysis of ERCOT's revenue inadequacy stated that, while ERCOT is not the only revenue inadequate electricity market in the United States, other revenue inadequate regions exhibit a substantial oversupply of capacity. CRA points out that ERCOT is unique in its persistent revenue inadequacy for new generation at a time when there is an urgent need to construct new capacity (Plewes, 2013).

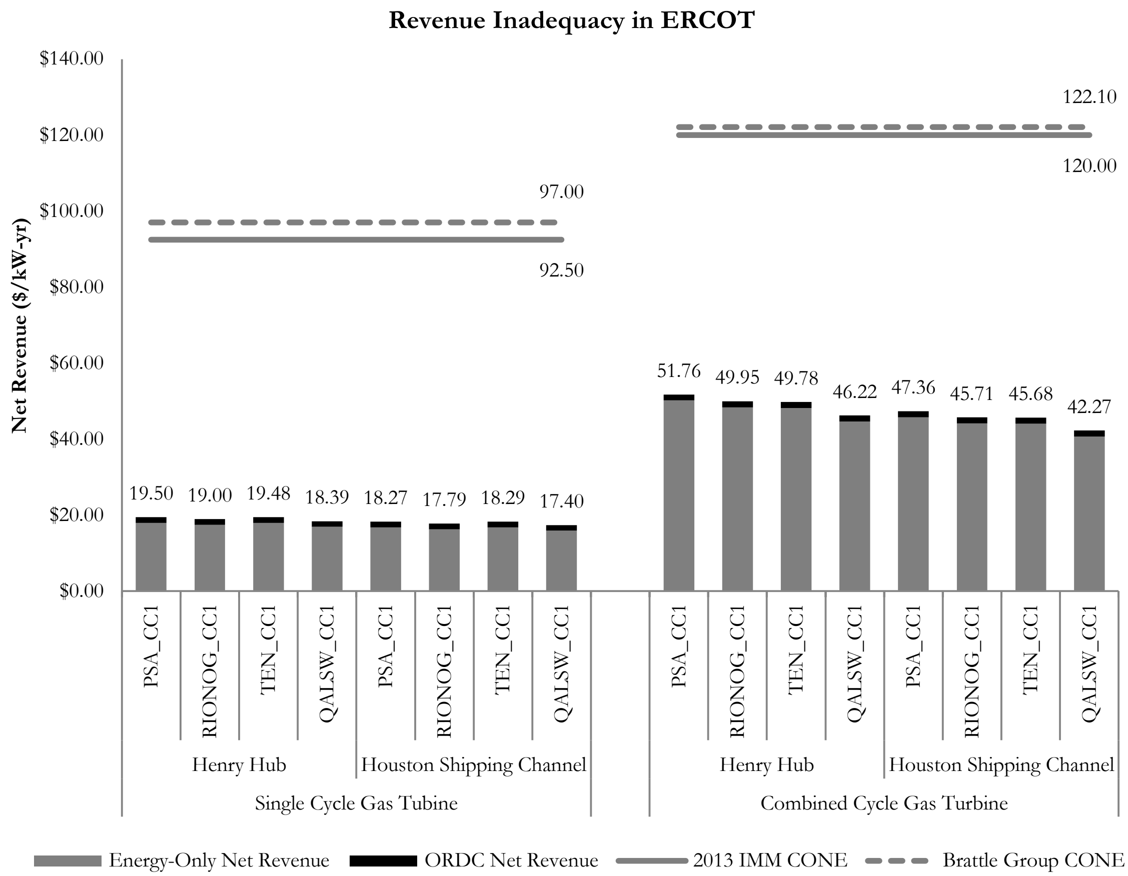

Figure 14: Generator net revenues across all scenarios examined within the scope of this study. The net revenues are compared to fixed cost estimates from Potomac Economics and The Brattle Group. The scenario analysis shows persistent revenue inadequacy despite the ORDC's implementation (Potomac, 2014; Newell, 2014).

ORDC revenues are also insubstantial in comparison with resource adequacy revenues from capacity auctions in other markets. I compared annualized resource adequacy revenue from ERCOT's ORDC with annual capacity auction revenue from the Pennsylvania, Jersey, Maryland Interconnection (PJM), the New York ISO[40] (NYISO), and the Midcontinent ISO (MISO). This comparison is shown in Figure 15, clearly illustrating the immense discrepancy in resource adequacy revenues between ERCOT and other comparable markets. Even the lowest capacity auction revenues from MISO are more than three times the resource adequacy revenues generated by ERCOT's ORDC.

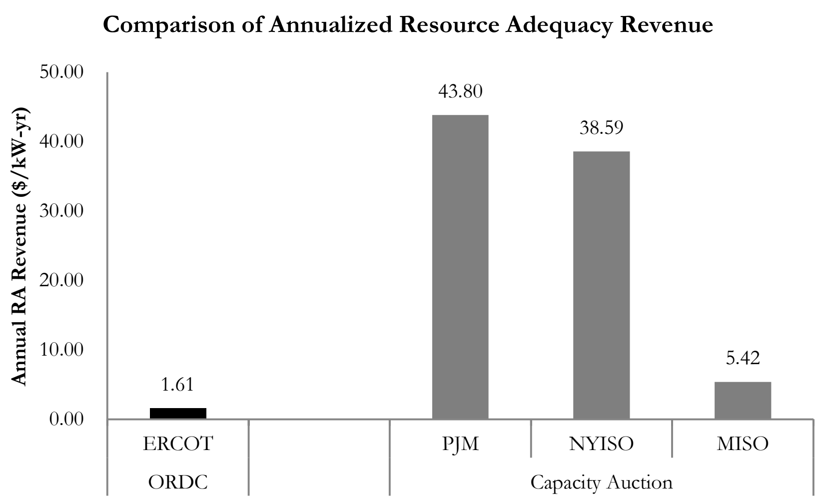

Figure 15: A comparison of annualized revenue resultant from the ORDC with comparable revenue from the most recent PJM, NYISO, and MISO capacity auctions (PJM, 2015; NYISO, 2015; MISO, 2015).

In addition to providing insufficient net revenue additions for meaningful resource adequacy benefits, the ORDC's revenue additions were highly variable on a month-to-month basis over the course of the study period. Figure 16 displays this variability for both SCGT

[40] Independent System Operator.

and CCGT resource technologies. The graph illustrates that a hypothetical single cycle plant would have earned anywhere between $5,000 and $183,000 in a given month from ORDC price additions; the equivalent range for a combined cycle plant was $9,000 to $277,000. Both ranges show a degree of variability which indicates that ORDC revenue additions are highly unpredictable and inconsistent.

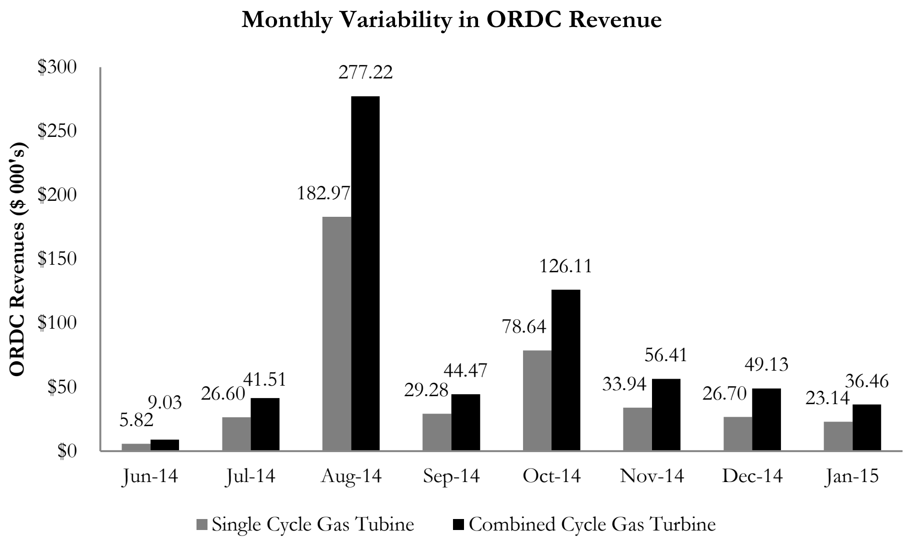

Figure 16: ORDC Revenue on an absolute monthly basis for SCGT and CCGT plants over the period of study.[41]

	Monthly ORDC Revenue ($ 000's)	
	Single Cycle Gas Turbine	Combined Cycle Gas Turbine
Mean	$50.89	$80.04
Standard Deviation	$57.25	$86.36

Table 7: Mean and standard deviations of monthly ORDC revenue based on the data from Figure 16.

[41] Scenario uses PSA_CC1 for Settlement Point and Henry Hub for Natural Gas Hub. Other scenarios yield similar results in terms of variability.

The mean and standard deviation of Figure 16's data are presented in Table 7 to provide information on the distribution of monthly ORDC revenue additions. Monthly ORDC revenue is in fact so variable that the standard deviation of its monthly distribution is larger than its mean for both SCGT and CCGT plants. This presents an incredible amount of revenue uncertainty for generators in ERCOT, which has very real economic consequences over the long-term. Revenue inconsistency creates difficulty in predicting a generator's future cash flows, which reduces its ability to guarantee the timeliness of debt interest and principal payments. This uncertainty creates risk for creditors, who in turn demand a higher return on their initial loan. The net effect of revenue uncertainty is therefore an increased cost of capital for a system's generators, which further heightens the fixed entry cost they must recover to profit from an investment. Given the fact that capacity markets tend to produce relatively stable and predictable revenue streams,[42] this data suggests that even if the ORDC were parameterized to provide revenue on par with a capacity auction, the ORDC would carry higher total system costs to achieve the same level of installed capacity (Cramton-Stoft, 2006). This additional cost comes in the form of a risk premium paid by investors to account for the ORDC's relative revenue uncertainty.

In summary, ERCOT's new Operating Reserve Demand Curve provides revenues to market participants that largely fail to provide meaningful resource adequacy benefits. Peaker net revenues after the ORDC's implementation still fall between 57% and 82% short of meeting expected entry costs and ORDC additions appear negligible when juxtaposed with

[42] Capacity markets guarantee a certain level of payment for a given period (3-5 years), they also provide this payment in lump-sum form, making it transparent and predictable for both investors and creditors (Cramton-Stoft, 2006).

comparable capacity market payments. This study therefore supports the conclusions of independent experts Plewes (2013), Newell (2014), and Potomac (2014) in finding that ERCOT's electricity market is revenue inadequate and faces serious resource inadequacy problems in the absence of major reform. I further build on the above works by finding that ERCOT's newest resource adequacy initiative, the ORDC, is a decidedly unsatisfactory solution to resolve the market's preexisting deficiencies.

VIII. Conclusion

Assuming that a resource adequacy program should be evaluated based on its clarity, consistency, and magnitude, this study finds that the ORDC fails to accomplish its goal of promoting resource adequacy by every possible metric.

In terms of clarity, the curve's calculation and mechanics are overly complex, relying on hidden administrative parameters that embody substantive market interference. In addition to contradicting the curve's premise as a market-based RA program (Hogan, 2012), this construction sends an opaque investment signal to market participants. From a consistency perspective, this study finds ORDC revenues to be highly variable on a monthly basis, presenting a coefficient of variability[43] equal to 1.1, which indicates significant irregularity and obfuscates future resource adequacy revenue. These clarity and consistency issues imply that given two payment streams of equal aggregate amount, one from a forward capacity market and one from ERCOT's ORDC, the increased clarity and reduced risk premium of the capacity market's payment stream help it generate a stronger investment signal. To achieve an equivalent investment level via an ORDC, ERCOT's payment stream would need to be significantly larger – at an additional cost of millions of dollars to Texas utility customers.

As for magnitude, the ORDC contributes minimal value to producer surplus, affording peaking generators a net revenue increase of ~3.5% for combined cycle plants and ~8.5% for single cycle plants over the course of the study period. Unfortunately, total

[43] Coefficient of variability is a measure of spread similar to the index of dispersion. It is calculated by dividing a sample's standard deviation by its mean.

annualized net revenues inclusive of ORDC payments still fell short of meeting expected producer fixed costs by between 57% and 82% across all scenarios. These results prove uninspiring in the context of Hogan's promise that an ORDC would "go a long way" toward meeting ERCOT's reliability and investment needs (Hogan, 2012). On the contrary, I view it as extremely unlikely that a utility, independent power producer, or financial sponsor who had previously elected to abstain from plant construction would be swayed in any convincing manner by the profitability profile seen in my findings.

Although comprehensive, this study is not without limitations. It relies on annualized projections from eight months of data in a historically seasonal industry. It further trusts a myriad of assumptions about plant operating characteristics reliant on present-day reference technologies without knowledge of individual investors' differing capabilities. Furthermore, this study was based on solely system-wide data, preventing more specific analysis of market participant bidding and plant utilization rates over the study period.

While these shortcomings are indisputably present, there exists no other method by which to produce an empirical study of ERCOT's ORDC in such rapid response to its implementation. Moreover, the study's assumptions were sourced from nationally recognized authorities on power generation, which lend them credibility. Seasonality issues, while not immaterial, are also unlikely to impact the incredibly decisive outcome of this research. I am further encouraged by the similarity of this study's results with those of similar studies conducted by Potomac Economics, The Brattle Group, and Charles River Associates. Based on this corroboration and the outsized margin for error inherent in my results, I firmly believe this paper's findings to be sound on a theoretical and empirical basis.

The ORDC's meager support for resource adequacy is likely not entirely by accident, but is instead indicative of the PUCT's hesitancy to make generator fixed-cost recovery a priority in ERCOT. The commission's lack of political willpower to undertake major resource adequacy reform has been well documented (Anderson, 2012; Hogan, 2012; Newell, 2012; Anderson, 2014) and consistent in the wake of the state's 2008 electricity market downturn. Unfortunately, EPA regulations and an aging generation fleet promise scores of imminent plant retirements, highlighting the need for capacity investment to prevent an estimated $18 billion in potential economic losses to the state of Texas over the next fifteen years (Plewes, 2014).

I find that the ORDC's implementation to this point represents a primarily cosmetic solution which was likely envisioned to appease financially stressed producers while skirting the expected costs associated with eliminating ERCOT's revenue deficiencies. By obscuring rather than confronting its state's resource inadequacy, the PUCT imperils ERCOT's grid reliability while admittedly possessing incomplete information regarding the long-term consequences of inaction. As for the ORDC itself, the relative inconsequentiality of the curve's payment stream, in concert with the policy's convoluted nature, present a lackluster signal to potential market entrants, rendering the ORDC suboptimal for resolving its stated resource adequacy objectives.

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Appendices

Appendix A – ORDC Revenue Additive Separability Derivation

The ORDC price adder (RTORPA) which is incorporated into real-time ERCOT real-time settlement point prices (RTSPP's) is made freely available for download from ERCOT's website. It is provided in 5 minute intervals in accordance with each Security Constrained Economic Dispatch (SCED)[44] run. I aggregate this RTORPA data and treat it as separable from the real-time locational marginal price (RTLMP) component of the resulting RTSPP. In order to prove that this is reasonable, I present the following derivation:

Beginning with the reserve price adder equation from ERCOT Nodal Protocols as of March 1, 2015[45]:

$$RTSPP = \sum_y \left(\left(\frac{TLMP_y}{\sum_y TLMP_y} \right) * \left(RTORPA_y + RTLMP_y \right) \right)$$

Where $TLMP_y$ represents the duration of each SCED interval and y represents all of the SCED intervals within a given 15 minute settlement period. This equation effectively represents the time-weighted sum of $RTORPA_y$ and $RTLMP_y$.

Separating and distributing, I find:

$$RTSPP = \sum_y \left(\left(\frac{TLMP_y}{\sum_y TLMP_y} \right) * \left(RTORPA_y \right) + \left(\frac{TLMP_y}{\sum_y TLMP_y} \right) * \left(RTLMP_y \right) \right)$$

$$= \sum_y \left(\left(\frac{TLMP_y}{\sum_y TLMP_y} \right) * \left(RTORPA_y \right) \right) + \sum_y \left(\left(\frac{TLMP_y}{\sum_y TLMP_y} \right) * \left(RTLMP_y \right) \right)$$

This shows that the time-weighted adder is separable from the time-weighted LMP's within each settlement interval. The same logic holds true within each hour (composed of four 15 minute settlement periods). This allows us to say that, on a time-weighted average basis:

---

[44] Security Constrained Economic Dispatch (SCED) is the real-time market evaluation of offers to produce a least-cost dispatch for online resources. In other words, it is the process by which ERCOT determines plant dispatch and baseline pricing of electricity. The process repeats every 5 minutes, with the results averaged within each settlement period to determine the price paid to each generation resource.

[45] This equation excludes the newly created Real-Time On-Line Reliability Deployment Price Adder (RTORDPA), which was added during the March iteration of the ERCOT nodal protocols. Study of the RTORDPA is outside of the scope of this paper, which utilizes data from before its creation.

$$RTSPP = RTORPA + RTLMP$$

$$\therefore\ RTORPA = RTSPP - RTLMP$$

$$\therefore\ RTLMP = RTSPP - RTORPA$$

Therefore, my model subtracts time-weighted average ORDC price additions from time-weighted average settlement point prices to separate ORDC revenue contributions from underlying locational marginal prices. This allows the model to clearly differentiate plant dispatch and economic performance between scenarios which include and exclude the ORDC's contributions. It also allows for isolation of ORDC revenue contributions for the analysis in Sections VI and VII.

Appendix B – Model Assumptions and Inputs

The dispatch model employed in this study makes use of a variety of assumptions regarding the marginal reference technology available for construction in ERCOT. These assumptions, employed in aggregate, construct the hypothetical "reference" plants that I use to evaluate the ORDC's success.

These assumptions and inputs can be separated into three categories: non-variable, user inputs, and reactive assumptions.

Non-Variable Assumptions

These assumptions are constant throughout the model and do not change from case to case.

- *Annual Inflation Rate*: Assumed constant at 2.5%. This assumption is consistent with models employed in Newell (2012), Newell (2014), and EIA (2014). This assumption is relatively inconsequential because only one month of analysis occurs in 2015.
- *Annual Heat Rate Degradation*: Assumed constant at 0.0%. The assumption is irrelevant within an 8-month timeframe.
- *Plant Commercial Operation Date*: Assumed to be June 1, 2014. The hypothetical reference plant is assumed to come online during the first day of ORDC implementation.
- *Projected Performance*: Performance for February, March, April, and May of 2015 is projected to continue (on average) as it did from June 1, 2014 to January 31, 2015. All annualized statistics shown in this study employ this assumption.

User Inputs

While running the dispatch model, I had significant ability to vary the analysis by altering user inputs. Altering the combinations of user inputs enabled me to test all reasonable possibilities of the ORDC's effectiveness, lending credibility to the model's results. The user inputs are as follows:

- *Marginal Resource Technology*: This input allows the user to select the type of hypothetical plant being evaluated. The model currently incorporates assumptions for Combined Cycle Gas Turbine (CCGT) plants and Single Cycle Gas Turbine (SCGT) plants. These two technology types are explicitly mentioned in Newell (2012) and Hogan (2012) as the two most likely marginal resource reference technologies in ERCOT.
- *Cost of New Entry Case*: The user has the opportunity to select between low, mid, and high cases for the gross cost of new entry (CONE) number chosen to be representative of investor fixed costs. These cost of new entry estimates are taken

directly from Newell (2014), which provided the estimates for CCGT and SCGT plants in ERCOT.

- *Plant Location (Settlement Point)*: The model provides functionality for changing the hypothetical plant's location between four selected representative resource nodes in ERCOT. Changing the plant's location accounts for locational variation in SPP's throughout Texas, directly impacting the plant's dispatch and revenue characteristics. For more comprehensive information on the representative settlement points, see Appendix D.
- *Natural Gas Hub*: Just as varying the settlement point allows the model to account for deviation in electricity prices, moving the natural gas hub sensitizes model outputs to discrepancies in plant fuel costs. The model currently includes monthly data for Henry Hub and Houston Shipping Channel prices.

Reactive Assumptions

The model's reactive assumptions change as a result of shifting user input. They are displayed here along with information about their sources and which user inputs control them.

- *Heat Rate ($MMBtu/MWh$)*: A power plant's heat rate is a measure of the plant's efficiency at converting natural gas into electricity. I use heat rates from Newell (2014), which the Brattle Group uses to characterize ERCOT's marginal natural gas resource technology. The heat rate used in each case is dependent on the type of natural gas plant selected by the user.

		Reference Technology	
		Single Cycle	Combined Cycle
Heat Rate			
Non-Summer	*(MMBtu/MWh)*	10.094	6.722
Summer	*(MMBtu/MWh)*	10.320	6.883

- *Variable Non-Fuel Operations & Maintenance Cost (VOM) ($\$/MWh$)*: In addition to variable fuel cost, there is a certain amount of assumed operations and maintenance (O&M) cost associated with dispatching a plant for any given period of time. In order to reflect this expected cost, I draw from the Brattle Group's (2014) report on PJM cost of new entry estimates, in which Newell presents a variable non-fuel O&M estimate in $\$/MWh$ for PJM natural gas plants with a 2018 online date. These estimates were adjusted backward for inflation to reflect a June 1, 2014 online date.

		Reference Technology	
		Single Cycle	Combined Cycle
Non-Fuel VOM	*($/MWh)*	$3.87	$2.36

- *Installed Capacity (MW)*: The capacity of a plant determines the amount of electricity it can generate in a given hour and is the basis for other cost assumptions reliant on plant size. My installed capacity data is also from Newell's (2014) report and varies based on the selected type of power plant.

		Reference Technology	
		Single Cycle	Combined Cycle
Installed Capacity			
Non-Summer	*(MW)*	418	627
Summer	*(MW)*	390	584

- *Gross Cost of New Entry ($\$/MW\text{-}yr$)*: In order to evaluate the effectiveness of the ORDC in boosting producer net energy margins, I compare the curve's revenue additions against fixed cost estimates provided by the Brattle Group for SCGT and CCGT combined cycle plants in Texas (Newell, 2014).

		Reference Technology	
		Single Cycle	Combined Cycle
Gross Cost of New Entry			
Low Cost Case	*($/MW-yr)*	$87,300	$109,900
Base Cost Case	*($/MW-yr)*	$97,000	$122,100
High Cost Case	*($/MW-yr)*	$121,300	$152,600

- *Start-up Fuel ($MMBtu/MW\text{-}start$)*: My model assumes that the plants require a certain amount of start-up fuel in excess of hourly generation fuel requirements. I draw these assumptions from a National Renewable Energy Laboratory report on power plant cycling costs (NREL, 2012). The start-up fuel required to dispatch a plant varies based on the type of plant selected.

		Reference Technology	
		Single Cycle	Combined Cycle
Start-up Fuel			
Non-Summer	*(MMBtu/MW-start)*	0.22	0.24
Summer	*(MMBtu/MW-start)*	0.18	0.19

- *Non-Fuel Start-up Cost ($\$/MW\text{-}Start$)*: Again drawing from the National Renewable Energy Laboratory Report on power plant cycling costs (NREL, 2012), I use an SCGT cost estimate of $0.95 per MW-Start to estimate chemical and water start-up cost. Unfortunately, the study did not collect enough data to make a comparable estimate for CCGT plants, so I reapply the SCGT estimate of $0.95 per MW-Start.

Appendix C – Model Calculations

The hourly dispatch model I used to evaluate the ORDC's effect on a marginal plant's merchant generation margin uses multiple equations to determine plant dispatch and profitability. For the sake of reproducibility, I include the most important of these equations below:

Implied Heat Rate

The implied market heat rate is calculated on a $(\$/MWh)$ basis for each individual hour y to provide reference for the plant's dispatch decision. The implied heat rate is compared with the plant's heat rate to determine whether or not producing electricity would be profitable in a given hour.

Implied Heat Rate (IHR_y)[46]*:*

$$IHR_y\left(\frac{MMBtu}{MWh}\right) = \frac{RTSPP_y\left(\frac{\$}{MWh}\right)}{NGP_y\left(\frac{\$}{MMBtu}\right)}$$

Where: $RTSPP_y$[47]: Average settlement Point Price (Electricity Price) within hour y.
NGP_y: Natural gas price for hour y.

Dispatch Margin

The Dispatch Margin is first calculated on a $(\$/MWh)$ basis in the following manner for each individual hour y. This margin calculation allows the model to determine whether or not it would be profitable for a plant to turn on in any given hour.

[46] The Implied Heat Rate or the "Break-even Natural Gas Market Heat Rate" is a calculation of a power market's electricity price divided by its natural gas price. It is termed such because only plants with operating heat rates lower than the implied market heat rate can operate profitably.
[47] $RTSPP_y$ includes revenue additions from the ORDC, as these should be factored in when determining plant dispatch profitability. The ORDC revenue additions are separated later in the Realized Performance section.

Dispatch Margin (DM_y):

$$DM_y\left(\frac{\$}{MWh}\right) = \max\left(0, \left(\left(IHR_y - HR\right) * NGP_y - VOM\right)\right)$$

Where: HR: Assumed plant heat rate.
VOM: Assumed plant variable operations and maintenance cost on a dollar per megawatt-hour basis.

The plant will dispatch (turn on) in any hour when $DM_y > 0$. It will likewise cease to produce in any hour when $DM_y < 0$.

<u>Generation</u>

Once the plant is dispatched, the amount of electricity generated in the hour is determined by using the plant's installed capacity.

Generation (G_y):

$$G_y(MWh) = if(dispatched) \rightarrow CAP(MW) * 1(hour)$$

Where: CAP: Assumed plant installed capacity.
1: Constant, signifies one hour.

<u>ORDC Revenue Additions</u>

ORDC revenue additions ($RTORPA_y$) are averaged on a time-weighted basis using the method described in Appendix A. They are separated from merchant energy revenues in the Realized Performance section of the model.

<u>Realized Performance</u>

In order to calculate the producer's merchant generation margin, certain realized performance metrics are needed.

Merchant revenue is defined as the energy-only revenue received from generation less the ORDC revenue addition.

Merchant Revenue (MR_y):

$$MR_y(\$\ 000's) = \frac{\left(RTSPP_y\left(\frac{\$}{MWh}\right) - RTORPA_y\left(\frac{\$}{MWh}\right)\right) * G_y(MWh)}{1000}$$

Where: $RTORPA_y$: Time-weighted average ORDC revenue additions for hour y.

ORDC price additions are then calculated for each hour as a separate revenue stream. This allows for the isolation of the ORDC's effect.

ORDC Revenue ($ORDC_y$):

$$ORDC_y(\$\ 000's) = \frac{RTORPA_y\left(\frac{\$}{MWh}\right) * G_y(MWh)}{1000}$$

Fuel Cost (F_y):

$$F_y(\$\ 000's) = \frac{NGP_y\left(\frac{\$}{MMBtu}\right) * HR\left(\frac{MMBtu}{MWh}\right) * G_y(MWh)}{1000}$$

Variable Operations and Maintenance Cost (VOM_y):

$$VOM_y(\$\ 000's) = \frac{VOM\left(\frac{\$}{MWh}\right) * G_y(MWh)}{1000}$$

Start Costs (S_y):

$$S_y(\$\ 000's) = \frac{NFS\left(\frac{\$}{Start}\right) + (FS)\left(\frac{MMBTU}{Start}\right) * NGP_y\left(\frac{\$}{MMBtu}\right)}{1000}$$

Where: NFS: Assumed non-fuel startup cost.
FS: Assumed amount of fuel required per start.

Merchant Generation Margin

Merchant generation margin can then be calculated on a per-hour basis using the following formula:

Merchant Generation Margin (MGM_y):

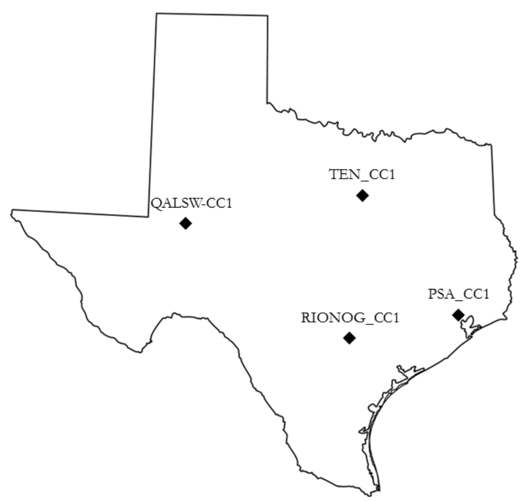
$$MGM_y(\$\,000's) = MR_y + ORDC_y - F_y - VOM_y - S_y$$

The merchant generation margin is the metric I use to determine the amount of fixed cost recovery a hypothetical representative plant would achieve over a given time period. The per-hour results are summed over monthly and yearly intervals to determine the plant's financial performance over a given period.

Appendix D – Settlement Point Locations

Real-time settlement point prices (RTSPP's) paid to generation resources are made up of two primary components, the baseline real-time locational marginal price (RTLMP) and the ORDC revenue addition (RTORPA). While ORDC revenue additions are identical throughout ERCOT's real-time spot market, the underlying RTLMP's vary by location to account for factors such as varying load, transmission congestion, and day-ahead market orders.

In order to provide thorough analysis of hypothetical plant dispatch in ERCOT, I selected four representative settlement points to capture locational variation in electricity price data. These settlement points are each located in a different one of ERCOT's four "congestion zones" (North, South, West, and Houston), which minimizes uncaptured locational variation. All four settlement points represent legitimate or hypothetical natural gas plants to lend credibility to the use of their RTSPP's in my model. A map detailing the location of the representative settlement points is shown below.



Settlement point descriptions:

- **QALSW_CC1 (West Zone):** Located in Odessa, TX, this settlement point provides prices received by the Quail Run Generating Station, a 550 MW combined cycle natural gas facility owned by Starwood Capital Management. The facility is located in the middle of the Permian Basin, which is the largest petroleum-producing basin in the United States. The majority of the plant's generated electricity serves energy-intensive oil exploration, production, and refining facilities in the surrounding area.

- **TEN_CC1 (North Zone):** Located in Cleburne, TX (near Dallas), this settlement point provides a hypothetical SPP which would be received by a combined cycle natural gas facility were it to be built in Johnson County, TX.
- **PSA_CC1 (Houston Zone):** Located in Channelview, TX (near Houston), this settlement point provides prices received by the Optim Energy Altura Cogen Plant, a 564 MW plant in Harris County owned by Dynegy, Inc. The plant sells the majority of its produced power on a short-term basis into ERCOT's market to serve Houston's regional demand.
- **RIONOG_CC1 (South Zone):** Located in Seguin, TX (near San Antonio), this settlement point provides prices received by the Rio Nogales Power Project, an 800 MW natural gas plant in Guadalupe County owned by Tenaska Capital Management. The plant uses the majority of its energy to offset load from San Antonio in the real-time market.

Appendix E – SPP Data Script

After submitting an Information Request for real-time settlement point prices (RTSPP's) to ERCOT's market information team, I received historical RTSPP's from January 1, 2014 to February 1, 2015.

The resultant SPP's were provided as separate files for each 15 minute settlement interval. I used the python script below to consolidate RTSPP data into a format usable by my model. This script only takes RTSPP's from the four reference settlement points described in Appendix D.

```
'''''
Created on Mar 23, 2015

@author: maxlipscomb
'''

import os
import csv

def main():
    wrangle()

#primary function
def wrangle():
    output = 'Output.csv'
    workingdir = 'RELATIVE_FILE_PATH'
    #2014 data: './SPP Data 2/5_SPP_RN_LZ_Hb_2014'
    #2015 data: './SPP Data 2/6_SPP_RN_LZ_Hb_2015_through_0304'

    fArray = os.listdir(workingdir)

    tempArray = []

    #Discard non-CSV's
    for filename in fArray:
        if filename[-3:] == 'csv':
            tempArray.append(filename)

    #array to store final output
    storage = []
    #iterate through CSV's
    for filename in tempArray:
        #array to store each file's data
        temp = []
        counter = 0
        filepath = workingdir + '/' + filename
        with open(filepath, 'rU') as csvfile:
            spamreader = csv.reader(csvfile, delimiter=',', quotechar='|')

            #each row is a list containing all items
            for row in spamreader:
                if counter == 1:
                    temp.append(row[0])
```

```
                    temp.append(row[1])
                    temp.append(row[2])
                    temp.append(0)
                    temp.append(0)
                    temp.append(0)
                    temp.append(0)

                if counter >= 1:
                    if row[3] == "PSA_CC1":
                        temp[3] = row[5]
                    if row[3] == "RIONOG_CC1":
                        temp[4] = row[5]
                    if row[3] == "TEN_CC1":
                        temp[5] = row[5]
                    if row[3] == "QALSW_CC1":
                        temp[6] = row[5]
                counter += 1

        storage.append(temp)

    #write stored data into an output csv
    with open(output, 'w') as csvfile:
        spamwriter = csv.writer(csvfile, delimiter=',', quotechar='|', quoting=csv.QUOTE_MINIMAL)
        for item in storage:
            spamwriter.writerow(item)

if __name__ == "__main__":
    main()
```

Appendix F – Example Power Plant Monthly Operation

The table below presents a hypothetical monthly statement of operations for a single cycle gas turbine power plant over the study period.[48]

Statement of Operations	Jun-14 A	Jul-14 A	Aug-14 A	Sep-14 A	Oct-14 A	Nov-14 A	Dec-14 A	Jan-15 A	Realized	Projected Annual
Merchant Generation										
Merchant Generation Hours	89	97	139	67	85	61	27	24	589	884
Merchant Capacity (MW)	404	404	404	404	404	404	404	404	404	404
Merchant Generation (GWh)	**36**	**39**	**56**	**27**	**34**	**25**	**11**	**10**	**238**	**357**
Merchant Revenues ($ 000's)										
Merchant Revenue	2,047.4	2,033.0	3,038.0	1,534.9	2,084.8	2,600.1	899.0	647.4	14,884.6	22,326.9
ORDC Revenue	5.8	26.6	183.0	29.3	78.6	33.9	26.7	23.1	407.1	610.7
Total Revenue	**2,053.2**	**2,059.6**	**3,221.0**	**1,564.2**	**2,163.4**	**2,634.1**	**925.7**	**670.6**	**15,291.7**	**22,937.6**
Variable Costs ($ 000's)										
Fuel Costs	(1,473.9)	(1,494.9)	(2,117.7)	(1,018.5)	(1,243.1)	(981.6)	(383.8)	(302.3)	(9,015.8)	(13,523.6)
VOM	(134.3)	(146.3)	(209.7)	(101.1)	(128.2)	(98.6)	(43.7)	(39.8)	(901.7)	(1,352.6)
Start Costs	(16.5)	(16.6)	(19.2)	(13.2)	(18.2)	(16.5)	(13.6)	(7.9)	(121.8)	(182.7)
Total Generation Costs	**(1,624.6)**	**(1,657.9)**	**(2,346.6)**	**(1,132.8)**	**(1,389.5)**	**(1,096.8)**	**(441.0)**	**(350.0)**	**(10,039.2)**	**(15,058.9)**
Net Revenues ($ 000's)	**428.6**	**401.7**	**874.3**	**431.4**	**773.9**	**1,537.3**	**484.7**	**320.6**	**5,252.5**	**7,878.7**
Net Revenue ($/kW-yr)										
Energy-Only Net Revenue	1.05	0.93	1.71	1.00	1.72	3.72	1.13	0.74	11.99	17.99
ORDC Net Revenue	0.01	0.07	0.45	0.07	0.19	0.08	0.07	0.06	1.01	1.51
Total Net Revenue	**1.06**	**0.99**	**2.16**	**1.07**	**1.92**	**3.81**	**1.20**	**0.79**	**13.00**	**19.50**
Capacity Factor (%)	*12.18%*	*13.28%*	*19.03%*	*9.17%*	*11.64%*	*8.35%*	*3.70%*	*3.29%*	*10.08%*	*10.08%*
ORDC % of Total Revenue	*0.28%*	*1.31%*	*6.02%*	*1.91%*	*3.77%*	*1.31%*	*2.97%*	*3.57%*	*2.74%*	*2.74%*
ORDC % of Generation Margin	*1.36%*	*6.62%*	*20.93%*	*6.79%*	*10.16%*	*2.21%*	*5.51%*	*7.22%*	*7.75%*	*7.75%*
% of ORDC Revenues Captured									*93.31%*	*93.31%*
ORDC % CONE Coverage	*0.01%*	*0.07%*	*0.47%*	*0.07%*	*0.20%*	*0.09%*	*0.07%*	*0.06%*	*1.04%*	*1.56%*
Net Revenue % CONE Coverage	*1.09%*	*1.03%*	*2.23%*	*1.10%*	*1.97%*	*3.92%*	*1.24%*	*0.82%*	*13.40%*	*20.10%*

[48] Settlement point set to PSA_CC1; Natural Gas Hub set to Henry Hub; CONE set to Brattle Group base case.

The table below presents a hypothetical monthly statement of operations for a combined cycle gas turbine plant over the study period.[49]

Statement of Operations	Jun-14 A	Jul-14 A	Aug-14 A	Sep-14 A	Oct-14 A	Nov-14 A	Dec-14 A	Jan-15 A	Realized	Projected Annual
Merchant Generation										
Merchant Generation Hours	494	470	446	430	396	294	271	434	3,235	4,853
Merchant Capacity (MW)	606	606	606	606	606	606	606	606	606	606
Merchant Generation (GWh)	**299**	**285**	**270**	**260**	**240**	**178**	**164**	**263**	**1,959**	**2,938**
Merchant Revenues ($ 000's)										
Merchant Revenue	11,834.8	10,625.8	10,979.2	9,529.2	8,920.8	8,704.6	5,620.6	7,451.3	73,666.4	110,499.6
ORDC Revenue	9.0	41.5	277.2	44.5	126.1	56.4	49.1	36.5	640.3	960.5
Total Revenue	**11,843.8**	**10,667.3**	**11,256.4**	**9,573.7**	**9,047.0**	**8,761.0**	**5,669.7**	**7,487.8**	**74,306.7**	**111,460.1**
Variable Costs ($ 000's)										
Fuel Costs	(8,164.3)	(7,228.8)	(6,781.2)	(6,523.3)	(5,779.4)	(4,729.5)	(3,850.5)	(5,465.0)	(48,522.2)	(72,783.2)
VOM	(682.2)	(649.0)	(615.9)	(593.8)	(546.8)	(435.9)	(401.8)	(659.5)	(4,584.8)	(6,877.2)
Start Costs	(31.6)	(33.7)	(40.6)	(38.6)	(41.9)	(39.3)	(39.2)	(42.8)	(307.7)	(461.5)
Total Generation Costs	**(8,878.1)**	**(7,911.5)**	**(7,437.7)**	**(7,155.6)**	**(6,368.2)**	**(5,204.7)**	**(4,291.5)**	**(6,167.3)**	**(53,414.7)**	**(80,122.0)**
Net Revenues ($ 000's)	**2,965.7**	**2,755.8**	**3,818.7**	**2,418.1**	**2,678.8**	**3,556.3**	**1,378.2**	**1,320.5**	**20,892.0**	**31,338.1**
Net Revenue ($/kW-yr)										
Energy-Only Net Revenue	4.88	4.48	5.85	3.92	4.22	5.78	2.19	2.12	33.45	50.17
ORDC Net Revenue	0.01	0.07	0.46	0.07	0.21	0.09	0.08	0.06	1.06	1.59
Total Net Revenue	**4.90**	**4.55**	**6.31**	**3.99**	**4.42**	**5.87**	**2.28**	**2.18**	**34.50**	**51.76**
Capacity Factor (%)	*67.63%*	*64.34%*	*61.06%*	*58.87%*	*54.21%*	*40.25%*	*37.10%*	*59.41%*	*55.36%*	*55.36%*
ORDC % of Total Revenue	*0.08%*	*0.39%*	*2.52%*	*0.47%*	*1.41%*	*0.65%*	*0.87%*	*0.49%*	*0.87%*	*0.87%*
ORDC % of Generation Margin	*0.30%*	*1.51%*	*7.26%*	*1.84%*	*4.71%*	*1.59%*	*3.56%*	*2.76%*	*3.06%*	*3.06%*
% of ORDC Revenues Captured									*97.92%*	*97.92%*
ORDC % CONE Coverage	*0.01%*	*0.06%*	*0.37%*	*0.06%*	*0.17%*	*0.08%*	*0.07%*	*0.05%*	*0.87%*	*1.30%*
Net Revenue % CONE Coverage	*4.01%*	*3.73%*	*5.17%*	*3.27%*	*3.62%*	*4.81%*	*1.86%*	*1.79%*	*28.26%*	*42.39%*

[49] Settlement point set to PSA_CC1; Natural Gas Hub set to Henry Hub; CONE set to Brattle Group base case.