SPEER

The South-central Partnership for Energy Efficiency as a Resource

SPEER Incremental Demand Response Report

May 2015

Incremental Demand Response Study: ERCOT Case Study

Summary of Study

Demand Response (hereafter, DR) is a term used today to describe the ability of consumers, individually or as part of an aggregation to strategically reduce, or shift their demand for electricity in response to market signals or incentives. It can involve changes to industrial or commercial processes, or adjustments to energy using equipment, or, if permitted, the use of on-site generation or storage. DR can be "economic," dispatched in response to price signals, or responsive to emergency or reliability conditions, as determined by the utility or system operator.

ERCOT, the Electric Reliability Council of Texas, is the independent system operator (ISO) in the ERCOT region of Texas.[1] As such, it manages the real-time flow of electricity across the transmission system to maintain the safe and reliable delivery of electricity to Texas consumers. In its capacity as the ISO, ERCOT also operates the wholesale Nodal Market. This nodal market was launched on Dec. 1, 2010, and features locational marginal pricing (LMP) for generation at more than 8,000 nodes, a day-ahead energy and ancillary services co-optimized market, day-ahead and hourly reliability-unit commitment, and congestion revenue rights.[2] This competitive market continuously matches buyers and sellers to determine the wholesale price of electricity in 15-minute intervals. The price tends to climb as demand for electricity rises, often because older less efficient generation plants must be called upon for infrequent high demand periods. Strategic reductions of consumer demand, acting as resources for the system, especially during periods of high demand, or during emergencies, can eliminate the need for these marginal resources and, thereby, reduce the marginal cost of power for any given increment of time, and may reduce environmental impacts of the power system.

The purpose of this study is to estimate the financial impact that stimulation of additional demand response (DR) would have on Texas consumers. To do that, we have used the available historical data to estimate the likely impact of load reductions within the ERCOT footprint on several critical days between 2011 and 2013. In the case of years 2012 and 2013, available data allowed us to estimate potential savings from this incremental economic DR, by modeling what the system average LMP would have been if there had been various levels of additional supply from DR resources. In this context, "economic DR" is DR by customers that

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[1] ERCOT is a private corporation formed by stakeholders under the authorization of the legislature and under the oversight of the Public Utility Commission. ERCOT both oversees the planning for transmission interconnection of the region and administers wholesale energy and ancillary services markets.

[2] LMP is the offer-based marginal cost of serving the next increment of Load at a given network node.

would be willing to voluntarily respond by removing load from the ERCOT system as a result of marginal price signals greater than the respective loads offer price. To estimate the potential savings, we modeled the several specific days during years 2012 and 2013 that exhibited intervals of sustained marginal prices above assumed 'strike prices,' or offer prices for DR. That is to say we identified the specific market intervals during which average locational prices were high enough that it would be reasonable to assume that given the opportunity, some loads would readily opt to curtail their energy consumption in order to earn the market price for wholesale electricity. We then examined the available supply curve data (generation offer prices) for all resources offered into the ERCOT wholesale market during those intervals, and added to the supply curves our assumed quantities of additional DR at the assumed strike prices.[3] Then, holding average system demand for the modeled hours constant, we estimated what the system average price would have been by observing the strike price at which the offered quantities from the modified supply curves intersected system demand.

We then calculated the total savings associated with the new, now lower marginal price, at a level of system demand that was reduced by the amount of incremental DR that would have cleared in the modeled hours. Not only is the lower marginal price applicable to the marginal generation unit(s) still needed to serve load, however: All units dispatched by ERCOT for the increment of time considered would have also been paid the lower marginal prices in the applicable intervals – leveraging potentially substantial overall customer savings.[4]

In the case of 2011, at the time of this study ERCOT had not published equivalent 2011 historic data as it has for 2012 and 2013.[5] This level of data is a requirement to model the impact of additional economic DR in ERCOT's energy market auctions. Fortunately, however, we did have sufficient 2011 data to model the impact of additional emergency DR in severe system conditions as existed in 2011 but not in 2012 or 2013.[6] We assumed that the additional emergency DR would have reduced the level of involuntary load shedding during periods of supply shortfall. For this part of the study, we utilized Value

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[3] Supply curves are upward sloping, representing the positive relationship between willingness to supply and price. That is, at higher prices, suppliers will be willing to increase their quantity supplied.

[4] Units included in the dispatch to serve load, but not at the "margin" setting the marginal price are referred to as "infra-marginal."

[5] The issues were communicated by ERCOT in market notices (W-B120710), which included the 48-hour Aggregate Supply Curve for Non-Wind Resources report and the 48-hour Aggregate Supply Curve for Wind Resources.

[6] For example, using the February 2, 2011 firm load shedding information and timeline, we assumed that additional DR (EILS), in 500 MW increments, would have reduced the amount of firm load shedding by the same amount. We then multiplied the MWh of additional deployed DR by an assumed Value of Lost Load (VOLL) to arrive at a minimum savings to consumers.

of Lost Load (VOLL) estimates as included in a London Economics study commissioned by ERCOT.[7] VOLL is the value that represents a customer's "willingness to pay" for reliable electricity service. It is generally measured in dollars per unit of power (e.g., megawatt hour, "MWh"). As noted in the London Economics study for ERCOT, accurately estimating VOLL for a given region and a specific type of outage is a challenging undertaking -- as VOLL depends on multiple factors such as the type of customer affected, regional economic conditions and demographics, time and duration of outage, in addition to other specific traits of a given outage.

2012 and 2013 Findings

As noted above, we set out to analyze the impact of economic DR on several days during relatively mild summers (2012 and 2013). We found that including 1500 megawatts of economic DR—approximately 2.5% of total demand—would bring savings of $200 million only on the five days we modeled.

Available data allowed us to estimate potential savings from incremental "economic DR," by identifying the lower marginal price due to incremental economic DR availability.[8] To estimate the potential savings, we selected several days during years 2012 and 2013 that exhibited intervals of sustained marginal prices above an assumed "strike ("offer") price" for DR.[9] That is to say, we identified several market intervals during which average locational prices were high enough that it would be reasonable to assume that given the opportunity, some loads would readily opt to curtail their energy consumption in order to earn the market price for wholesale electricity. We then examined the available supply curve data for all resources offered into the ERCOT wholesale market during those intervals, and added to the supply curves our assumed quantities of additional DR at the assumed strike prices. Then, holding average system demand for the modeled hours constant, we estimated what the system average price would have been by observing the strike price at which the offered quantities from the modified supply curves intersected system demand.

Savings were then calculated by utilizing the new, lower marginal price inclusive of the incremental economic DR, at a level of system demand that was reduced by the amount of incremental DR that would have cleared in the modeled hours. Of course, not only is the lower marginal price applicable to the marginal generation unit(s) still needed to serve load, all infra-marginal units dispatched by ERCOT for the increment of time considered would have also be paid the lower marginal prices in the applicable

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[7] There is no single agreed upon VOLL figure for ERCOT, we assumed that VOLL fell within the range provided in, ***Briefing paper prepared for the Electric Reliability Council of Texas, Inc. by London Economics International LLC***, June 27, 2013, and that ERCOT would not set a price cap higher than their estimation of VOLL and, therefore, the current price cap is a reasonable (and probably a conservative) proxy for VOLL.

[8] We worked with publicly available ERCOT data from reports published pursuant to ERCOT's Protocols.

[9] We utilized three tranches of DR offers, 500 MW at $300/MWh; an additional 500 MW at $500/MWh; and an additional 500 MW at $1,000/MWh.

intervals – leveraging potentially substantial overall customer savings.[10]

Although this analysis focuses on only 5 days during 2012 and 2013, the estimated savings associated with incremental, economic DR are substantial. Utilizing the methodology described above, our analysis estimated that incremental, economic DR would have resulted in wholesale market savings of over $200 million during the modeled intervals of high prices in ERCOT during 2012 and 2013. The following table presents the estimated Real Time Market (Security Constrained Economic Dispatch) savings for the intervals noted.[11]

SUMMARY OF SAVINGS IN 2012 AND 2013

	3/31/2012	4/26/2012	6/26/2012	9/3/2013	10/1/2013	Total
Hours of DR Deployment	2	1	3	1	2	9
MWh of DR Deployment	431	597	2986	1095	1361	6470
Savings from DR Deployment	$52,225,921	$2,954,514	$84,962,234	$38,207,754	$28,438,922	$206,789,345

2011 Findings

2011 was a record setting year in ERCOT, with a new peak demand record of 68,379 MW on August 3, 2011. In fact, the 2010 peak demand of 65,776 MW was broken on three consecutive days: Aug. 1, 2011 peak demand = 66,867 MW, Aug. 2, 2011 peak demand = 67,929 MW, and Aug. 3, 2011 peak demand = 68,379 MW. ERCOT also experienced a new weekend record on Sunday, Aug. 28 of 65,159 MW: an increase of 5% over the previous record. In addition, ERCOT set a new winter peak record of 57,282 MW on February 10, 2011.

In examining the 2011 data, we found a February 2nd event of firm load shedding (FLS). During the early morning hours on this day, ERCOT experienced extreme cold weather, record electricity demand levels, and the loss of numerous electric generating facilities.[12] This firm load shedding event lasted 7

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10 Infra-marginal refers to the units inside of, as opposed to at, the margin.

11 March 31, 2012, Hour Beginning (HB)16 and HB17; April 26, 2012, HB16; June 26, 2012, HB14, HB15, HB16; September 3, 2013, HB16; and October 1, 2013, HB15, HB16.

12 IMM Report to the PUCT, April 21, 2011, p. 1

hours and 25 minutes, during which several "blocks" of load were shed.[13] To estimate the value of incremental "emergency" DR that could have been deployed during this event, we assumed that the cost of an additional 500, 1000, and 1500 MW was the same average $/MW-day value as the capacity that ERCOT actually purchased for delivery year 2011.[14] We then estimated the savings that might have accrued by applying three conservative tiers of Value Of Lost Load (VOLL) to the assumed additional DR that we modeled to offset firm load shed.

For our low-end estimate of VOLL, we chose the 2015 offer cap value for ERCOT -- $9,000 /MWh. We believe this is a conservative low-end estimate, based on the London Economics Study and our assumption that ERCOT and the PUCT would not implement a price cap that is higher than their estimate for VOLL. Our analysis showed that regardless of our VOLL assumptions there is a positive net benefit for 2011, and in several scenarios there is a positive net benefit over multiple years. Table 1 below shows the additional DR cost as a percentage of savings to consumers – the bang for the buck, so to speak. In all scenarios, and at all deployment levels we utilized, consumers would receive benefit greater than the cost of purchasing the emergency DR.

Table 1.

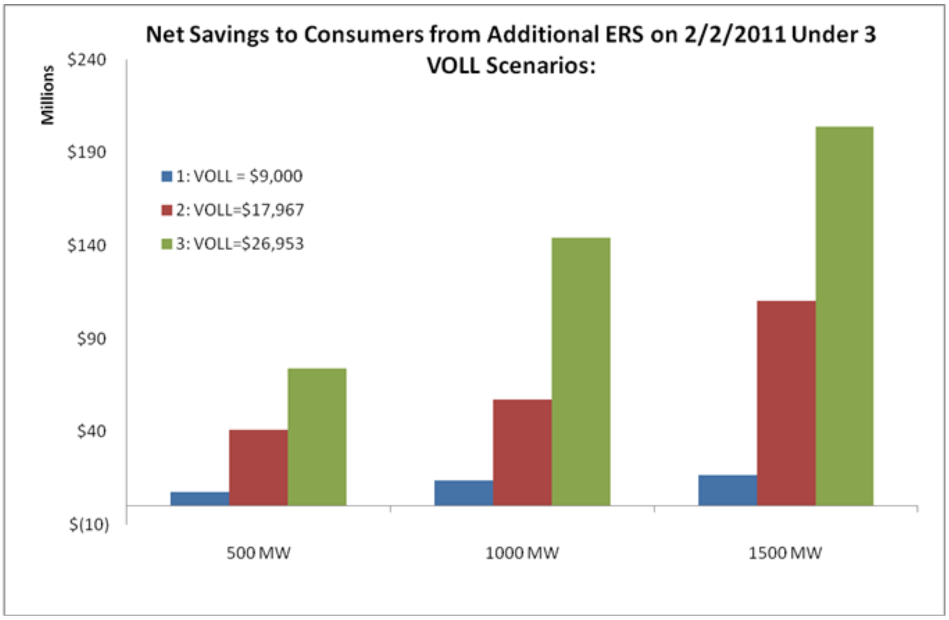
Additional Emergency DR Cost as a % of Savings to Consumers: 3 VOLL Scenarios			
	Additional DR (MW)		
Scenario	500 MW	1000 MW	1500 MW
1: VOLL = $9,000	77%	79%	82%
2: VOLL = $17,967	39%	47%	41%
3: VOLL = $26,953	26%	26%	28%

13 Energy Emergency Alert (EEA) Level 3 was declared by ERCOT at 5:43 a.m. All firm load was finally restored shortly after 1:00 p.m.

14 In our analysis, we ignored the current, arbitrary $50MM per year spend cap for ERS -- since the gross spending cap clearly prohibits substantial net savings.

Table 2 below summarizes the net savings under the 3 different VOLL scenarios to consumers from additional emergency DR utilization during the firm load shedding event on February 2, 2011.

Table 2.



Not surprisingly, the savings are even more striking at higher assumed VOLL. As a second tier of analysis, we choose to utilize as our mid-level assumption for VOLL the high-end of the residential class as discussed in the London Economics report of VOLL in ERCOT. This level showed savings in the range between $40.8 million for 500 MW of DR, to $110 million for 1500 MW of deployed DR.[15] Finally, we chose to model a high-end for VOLL representative of the value for commercial and industrial customers. For this we used half of the high end VOLL for Industrial customers as discussed in the same London Economics report. As is evident in the table above, 1500 MW of deployed DR at a VOLL of $26,953 would have resulted in avoided costs associated with firm load shedding of $203.8 million.[16]

[15] "Savings" in the context being used here accrues due to the avoidance of firm load shedding due to the addition of incremental, voluntary DR deployment.

[16] This VOLL is roughly ½ for the customer class in the London Economics study performed for ERCOT.

Thus, the range of estimated net savings for this single firm load shedding event is $7.6 million – with VOLL equal to $9,000 and deployed DR equal to 500 MW – to $203.8 million – with VOLL equal to $26,953 and deployed DR equal to 1500 MW.

Net Savings from Additional Emergency DR: 3 Scenarios			
Scenario	**500 MW Additional DR**	**1000 MW additional DR**	**1500 MW Additional DR**
1: VOLL = $9,000/MWh	$7,585,925	$13,746,850	$16,532,775
2: VOLL = $17,967/MWh	$40,838,550	$57,057,325	$110,088,475
3: VOLL = $26,953/MWh	$74,161,633	$144,055,708	$203,842,408

Conclusion

Theoretical arguments abound regarding the effect of active demand side participation in wholesale electric markets, but our analysis demonstrates the real value that such active participation could bring.[17] In very few days, and with very conservative assumptions, our analysis shows potential savings that must be considered significant. A modest number of consumers strategically reducing their demand for electricity in response to price signals on only five total days in 2012 and 2013 could have reduced power costs for all consumers in the state more than $200 million. The technology to facilitate this active participation by demand side resources is becoming evermore prevalent, and will allow virtually all loads to actively participate in ERCOT wholesale markets.

Although data were not available to estimate the total savings from incremental, economic DR in 2011, as was the case in 2012 and 2013, we were able to estimate the savings associated with incremental emergency DR in 2011. ERCOT experienced extremely cold winter weather, and extremely hot summer weather in 2011. No doubt, during this extreme year several intervals of high demand would have resulted in extremely high market prices; and based upon are findings in 2012 and 2013, incremental, economic DR would have been poised to participate and generate substantial savings.

Specifically, our analysis showed that on the single firm load shedding day, February 2, 2011, depending on the level of DR participation, and the VOLL assumed, the estimated net savings that could have been realized ranged between $7.6 million and $203.8 million: by any account a significant cost associated with a firm load shedding event that might have been mitigated by additional incremental DR.

All told, depending on which VOLL we use for 2011, on 6 days during 2011, 2012, and 2013, consumers could potentially have saved between $226MM and $422MM over the days we modeled in those years.[18] Taking the midpoint of conservative estimates of savings and VOLL, $110 million in costs associated with firm load shedding could have been avoided by active DR participation. Added to the estimated savings associated with incremental, economic DR in 2012 and 2013, this adds up to a potential savings for ERCOT consumers of up to over $300 million – in 6 scant days!

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[17] See, for example, Schweppe, Fred C., Michael C. Caramanis, Richard D. Tabors, and Roger E. Bohn. Spot Pricing of Electricity, Boston: Kluwer Academic, 1988. Print.

[18] The 6 days are equal to 5 days of incremental, economic, real time DR in 2012 and 2013, and one day of emergency DR in 2011.

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