Transition and Integration of the ERCOT Market with the Competitive Renewable Energy Zones Project

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ABSTRACT

In this study, we seek to explore the impact of a state level transmission expansion project, the Competitive Renewable Energy Zones (CREZ), whose goal is to integrate a massive amount of wind energy, on the wholesale market prices in the Electric Reliability Council of Texas (ERCOT). We find strong evidence for price convergence across ERCOT with accordance to the timing of the expansion of major sections of the CREZ. A variety of empirical analyses shows a gradual transition to a well-integrated market. We also find that regional-specific shocks became more important in terms of driving price change in other regions. Specifically, the impacts of Houston (demand) and the West (wind supply) on each other and the North and South regions have increased significantly. Our study contributes to the literature by connecting the expansion of physical transmission lines with electricity market integration.

Keywords: load zone price, market integration, transmission expansion, wind energy

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1. INTRODUCTION

Transmission constraints may lead to the failure to dispatch the lowest cost generation units in certain nodes and result in congestion. With the increasing penetration of renewable energy, mainly wind and solar, transmission congestion has become a serious challenge for grid operators and planners (DOE 2017a). In 2016, the power sector experienced the greatest annual increase in renewable energy capacity with 161 GW of new capacity added globally, which includes 54 GW of wind and 75 GW of solar power capacity (REN 2017). Total investments in renewable energy exceeded those for all fossil fuels combined reaching $241.6 billion (REN 2017). In the US, more than 60% of new capacity installations in 2016 were wind and solar, 8.7 GW and 7.7 GW respectively, followed by 33% (9 GW) in natural gas (IEA 2017). In 2016 wind turbines provide about 8% of total capacity and 6% of electricity generation (EIA 2017). The rapid development of wind power has been supported by technological improvement and reduced costs, renewable electricity policies including federal production tax credits and state renewable portfolio standards, and increased transmission capacity for integrating wind generation into grid.

The intermittent nature of renewable resources introduces a variety of challenges to the system, including, e.g., variability, uncertainty, location specificity, non-synchronous generation and

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low capacity factor (DOE 2017a). The impact of the integration of renewable energy into the grid depends on its penetration level. At a lower level, fluctuations from renewables are dominated by those of load and conventional units and thus do not affect reliability. The system can accommodate lower level of variable renewable energy through changes to the grid's operation, planning, expansion and other measures to improve the flexibility of the grid. Recent continued growth and penetration of intermittent capacity require reconsideration of the entire electrical system, for example, additional operating reserves, upgrading of poor infrastructures, expansion of the system to remote locations, and investments in flexible services, safe operations, and power system stability (Milligan et al. 2015; DOE 2017a). The investments in grid modernization and expansion could be substantial (Kassakian et al. 2011). According to estimates, investment in the grid capacity of the US would require about $100 billion per year between 2010 and 2030. In the UK the required investment is approximately £34 billion annually between 2014 and 2020, including onshore and offshore projects (Andoni et al. 2017). From the perspective of the grid itself, the investments will provide reliable electrical service to consumers, improve the resilience of the system to extreme conditions, enable the generation of a diverse mix of fuel resources that minimizes input costs, and would enhance the efficiency of the electricity market by relieving congestion.[1]

The last benefit is the focus of the current study. We seek to explore to what extent new transmission lines relieve congestion on the grid and the dynamics at play in such a situation. For this purpose, we analyze price divergence in four regions in the Electric Reliability Council of Texas (ERCOT). Relying on the law of one price (Woo et al. 2011b), we explore the impact of a state level transmission expansion project, the Competitive Renewable Energy Zones (CREZ), whose goal is to integrate a massive amount of wind energy to relieve congestion in the ERCOT market. As both the largest consuming state and the first-ranked in installed wind capacity in the US, the CREZ project in ERCOT serves as an excellent case study. Also, the construction of CREZ is exogenous to market conditions as it was built on a legislative mandate. From an econometric point of view, it is a unique opportunity for measuring the impact of transmission lines on market integration. Our study offers a variety of statistical models focusing on the impact of the CREZ on market integration. We provide a deeper understating for the mechanism of how physical progress in transmission lines is mapped to enhanced electricity market performances. To our best knowledge, we are the first study analyzing it empirically.

We find strong evidence for price convergence across ERCOT with accordance to the timing of the expansion of major sections of the CREZ project. First, cross-correlation coefficients of the West with other regions show an increasing pattern. As wind in the West is not correlated with load centers in ERCOT, this pattern is stronger for off-peak hours. Second, we use structural break tests to identify focal periods with respect to markets integration. The identified breaks accord well with the progress of the CREZ. Structural impulse responses suggest that with the CREZ in place, responses to the one-percentage-point price shock initiated in the West leads to 2.0–2.5 percent increases in all other regions, which is markedly different from the responses before the transmission expansion. We also find that regional-specific shocks became more important in terms of driving price change in other regions. Specifically, the impacts of Houston (demand) and the West (wind supply) on each other and the North and South regions have increased significantly. Lastly, volatility analysis shows that after the completion of the CREZ load zone prices become more volatile in all four regions during both peak and off-peak hours when wind is largely available in the West. The results presented in this research contribute to the literature by connecting the expansion of physical transmission lines with electricity market integration.

1. Chang et al. (2013) provides a comprehensive review of the socio-economic benefits.

The rest of the paper is organized as follows. Section 2 provides background information on the ERCOT and the associated wholesale market, its wind energy development, and the CREZ project, followed by a brief literature review on the integration of electricity markets in Section 3. Section 4 presents the empirical methods and analytical results. Section 5 concludes.

2. BACKGROUND

We start with a brief introduction on the ERCOT, the wind energy in ERCOT, the CREZ project and the wholesale market.

2.1 ERCOT

The Electric Reliability Council of Texas provides about 90% of the state's electricity. As an independent system operator, ERCOT manages the power flow to approximately 24 million consumers via the electrical grid that connects more than 46,500 miles of transmission lines and more than 570 units of power generation. Contained entirely within Texas, ERCOT is an electrical island with an installed generation capacity of more than 78 GW. A record peak demand of 71,110 MW occurred on August 11, 2016 (ERCOT 2017).

The mix of energy sources has changed over the years due to changing economic circumstances and regulatory requirements as well as technical innovations. Over the last 20 years, gas steam and coal, which together accounted for 75% of installed capacity (50% and 25% respectively) in the late 1990s, now account for only 34.7% (13.8% and 20.9% respectively). During this period, renewables installed capacity (mainly wind) and simple and combined cycle generation have increased from 5% to 54.2% (36.8% and 17.4% respectively). These changes can be attributed mainly to low natural gas prices, technical advances, and policy support for renewable energy (Daneshi and Srivastava 2011; Matevosyan and Du 2017).

2.2 Wind Energy in ERCOT

Wind power developed rapidly in Texas due to superb wind conditions, mainly in West Texas, the Texas Panhandle and along the Gulf Coast (Matevosyan and Du 2017). Texas has annual potential wind capacity of 1,347,992 MW and an annual potential generation in 2020 of 5,085,832 GWh[2] (DOE 2017b). At the end of 2016, with 18,923 MW of wind capacity installed[3], Texas, if it were a country, would have been the sixth largest generator of wind power in the world, after Spain (23 GW) and followed by the UK (14.5 GW) (WWEA 2017). In March 2017, ERCOT recorded its highest wind generation of 16,141 MW, which accounted for 80% of the deployment of the wind capacity installed. Earlier that month, energy produced by wind reached a new record when it accounted for 50% of the ERCOT load (ERCOT 2017).

In addition to rich wind resources, several policy measures proved to be successful for increasing the wind penetration rate in Texas. At the state level, the Renewable Portfolio Standard (RPS) of Texas was set at 10,000 MW of renewables by 2025. This target was easily achieved in 2010 due to the creation of a system of tradable renewable energy credits. These credits granted

2. Wind power potential reflects the amount of wind power that is technologically possible to have installed in a given region. Source: https://windexchange.energy.gov/states/tx.

3. Source: http://www.ercot.com/gridinfo/generation.

wind producers on average $20 per MWh produced per year (Daneshi and Srivastava 2011).[4] At the federal level, a production tax credit (PTC) of 2.3 cents/kWh was granted for the first ten years of newly installed renewable capacity. The PTC was initiated in 1992 and has been extended several times since then. The most recent extension was signed in 2015 and includes an annual decrease of 20% in the credit as of 2017 until 2020 when it will disappear completely.

Currently, about 89% of the wind generation capacity has been installed in desolate areas in West Texas and the Texas Panhandle. The remaining 11% is located by the Gulf Coast near and south of Corpus Christi. In terms of their distance from urban centers and correlation with load, wind resources are better at the Gulf Coast (Potomac Economics 2017). However, this area is already well developed, so it is not suitable for further investments (Matevosyan and Du 2017).

Because of the growing demand for energy around major urban centers in the north central, south central and coastal regions of Texas and limited transmission to accommodate further wind projects, in 2005 the Texas Legislature passed SB 20 instructing the Public Utility Commission of Texas (PUCT) to create the Competitive Renewable Energy Zones.

2.3 CREZ

PUCT instructed ERCOT to develop a transmission plan to connect the West Texas and other areas with abundant wind resources and limited transmission capacity with the large load centers in the ERCOT region. By early 2009, five zones and a CREZ transmission plan were approved. Transmission providers were selected to build many sections of the transmission expansion project to interconnect areas and transport wind power from the west to the north and central parts of the state (Figure 1).

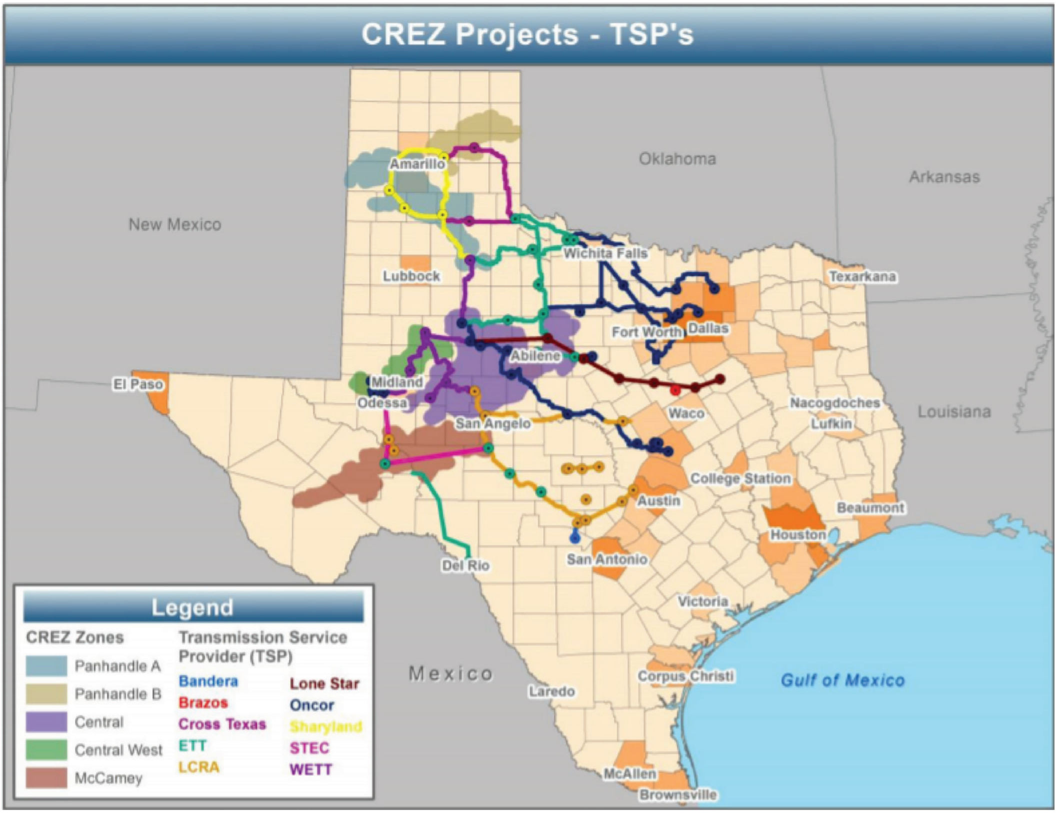
At the end of January 2014, the CREZ transmission project was completed. At a cost of about $6.8 billion, 3,600 right-of-way miles of high-voltage transmission lines were constructed with the ability to transmit 18.5 GW of wind power. The overall CREZ transmission program has provided the infrastructure necessary to approximately double Texas' renewable energy goals, as well as create the robust availability of 345 kV of electricity transmission to the West Texas area that has also helped address the increasing demand from the oil and natural gas industry.

Consequently, the completion of the CREZ transmission project has eliminated the longstanding limitation on the export of power from the West (Potomac Economics 2015).[5] Moreover, the expansion of the grid was followed quickly by the construction of new wind capacity. By early 2014, new wind projects totaling 6,947 MW signed interconnection contracts and additional projects of 24,000 MW were in the queue (DOE 2015). For example, the windiest area in Texas is Panhandle B (Figure 1), which was not connected to ERCOT before the CREZ project. Transmission lines were planned to accommodate 2.4 GW of wind power generation in Panhandle B. With only 200 MW installed by the completion of the CREZ, between 2014 and 2015 2.2 GW were added reaching the limit of the transmission system (Matevosyan and Du 2017). As a result, ERCOT had to start planning additional connections to that area not long after the completion of the CREZ. It is noteworthy that while the transmission lines expanded allowing the wind capacity to increase dramatically, wind curtailment decreased substantially. At the beginning of the project ERCOT suf-

4. By 2015, the value of renewable energy credit in ERCOT declined below 1$/MWh due to acute surplus (Barbose 2016).

5. For example, in 2011 the West to North interface constraint was binding more than 20 percent of the time. It was the most frequently occurring constraint in ERCOT that year, amounting to real-time congestions rent of approximately $95 million (Potomac Economics 2012).

Figure 1: CREZ Project



Source: ERCOT (2014).

fered from 17% wind curtailment. By the completion of the CREZ, this figure dropped to only 1.2% (DOE 2015), suggesting a transition to the better deployment of renewable resources. However, recent figures of 2016 suggest that congestions levels (mainly within and between the Houston and the North zones) and wind curtailment are rising again (Potomac Economics 2017).

2.4 The ERCOT Wholesale Market

The initial type of market implemented in 2001 was a zonal market. However, after several disadvantages in this approach became apparent (Tao et al. 2012; Zarnikau, Woo and Baldick 2014), in September 2003 PUCT directed ERCOT to develop a nodal market. The transition to nodal pricing took place in December 2010. It involved adopting locational marginal pricing (LMP) in more than 8,000 nodes with more than 500 settlement price points and the introduction of a day-ahead market.[6] The rationale for nodal pricing is well documented in the literature (e.g., Plancke et al. 2016). Fully functional LMP internalizes transmission constraints, thereby overcomes the problem of the missing market for transmission congestion.

The combination of Texas being a state leader in wind power capacity, the expansion of the CREZ project and the move to nodal pricing make ERCOT an excellent case study for investigating

6. In addition, the interval in operating times was reduced from 15 to 5 minutes, reducing the need for and cost of operating reserves.

the importance of expanding the transmission infrastructure to develop renewable energy. The positive impact of the CREZ on reducing system congestions has been documented in the annual state of the market reports of ERCOT. While our findings largely conform to the results of these reports, we offer an in-depth assessment of the project by mapping physical progress of the CREZ to statistical indices of market integration.

In line with the LMP reasoning, we measure the value of transmission lines in terms of the dynamics of price divergence across Texas along with the progress of the CREZ project. This study is timely and relevant, as many countries and regions are debating the necessity and value of investing substantial amounts in transmission lines to modernize their generation portfolio with renewable energy.

3. LITERATURE REVIEW

The crucial role of and social benefits brought by expansion of transmission facility are well recognized in the literature. In a deregulated market, by connecting geographically separate markets, additional transmission capacity not only relieves congestion, but also enhance competition and discourage the exercise of market power (Borenstein et al. 2000). Transmission constraint actively changes market conditions and consequently price and its variation (Birge et al. 2014; Clements et al. 2017). Davis et al. (2016) document the significant impact of the binding transmission constraint induced by the closure of a nuclear power plant in California on generation cost. Relaxing transmission constraint is found to greatly increase market surplus and reduce local market power in Indian electricity market (Ryan 2017). Wolak (2015) quantifies the competitiveness benefits of a transmission expansion policy in Alberta, Canada, resulting from lower wholesale market prices. Conversely, Mizra and Bergland (2015) show that generators in the Norwegian electricity market used information about transmission congestions to decide when to withhold output.

There is a small but growing body of literature pertaining to integration of electricity market. For example, Mansur and White (2012) provides empirical evidence in PJM market that an organized wholesale market substantially improved market efficiency by facilitating information sharing and encouraging trade. Various empirical methods are employed to investigate the integration of regional electricity markets, including, e.g., principal component analysis (Zachmann 2008), the generalized autoregressive conditional heteroscedasticity (GARCH) and dynamic conditional correlation (DCC) models (Higgs 2009), and common factor approach (Apergis et al. 2017).

4. EMPIRICAL ANALYSIS AND RESULTS

In this section, we present the empirical methods and results, mainly regarding the convergence and transition process of load zone prices induced by the connection of the CREZ transmission lines. We start with the analysis of the correlation coefficients of load zone prices illustrating the process of gradual integration across regional markets. Given the interconnected nature of the transmission network, we quantify the correlation changes of the West and all three other regions. We expect the new transmission lines and the newly constructed wind capacity in the West to increase correlation between regions. Relative price or price difference reflects the extent of connectedness between neighboring load zones, although the measure can be noisy sometime due to short term supply and demand dynamics (Woo et al. 2011a). The Bai-Perron structural break test (Bai and Perron 1998, 2003) is then applied on relative prices to identify the critical change points during the transition process of market integration. With the identified timing of the breaks, a structural vector autoregressive (SVAR) model is estimated before and after the CREZ related transition. To emphasize the impact of the market transition on not only price levels but also price volatility, we construct a range-based measure of daily volatility and regress it on various influencing factors.

We first introduce the price data we employ in this study. Hourly prices of the North, South, West and Houston regions (load zones) in the day-ahead wholesale markets over the period of December 1, 2010 to December 31, 2016 are obtained from ERCOT.[7] The analyzed prices are for respective load zones of individual regions.[8] For the remainder of the paper we use the terms regional prices and load zone prices interchangeably.

As discussed above, the prices are determined under nodal pricing system and reflect not only supply and demand conditions, but also transmission conditions in the local market. We generate three price series, daily average, daily peak, and daily off-peak, which are averages of 24-hours, peak-hours, and off-peak hour prices, respectively. We average prices to smooth local instantaneous occurrences that may generate outliers and introduce irrelevant noise into the analysis. Based on the definitions of ERCOT, peak hours refer to 7am–10pm from Monday through Friday excluding NERC (North American Electric Reliability Corporation) holidays. The rest of daily hours are considered as off-peak hours. There are 24 hourly prices in a typical day. But every year there is one day in the spring with 23 and one in the fall with 25 observations because of the clock adjustment for the daylight saving time.[9]

Figure 2 presents the average daily, peak and off-peak hour prices of the West Texas region in the day-ahead market (DAM) over the complete sample period. The corresponding summary statistics of all four regions and the number of negative prices in the West before and after January 2012 are reported in Table 1.[10] Besides the large difference in price levels, two observations are worth noting: (i) a significant number of negative prices in the West during off-peak hours in the early period of the sample, 15 in total before January 2012. Some negative prices also exist in the daily average prices and even peak hours before January 2012 (3 days altogether in each). This is reasonable given the fact that wind and generated electricity are the strongest in the early morning with limited demand which poses a burden to the system. But after connecting to other regions through the CREZ transmission lines, the West is able to supply wind power to demanding areas with positive economic values. And (ii) as expected, prices are more volatile during the peak hours than those of off-peak hours. With the CREZ transmission lines in place, electricity prices are relatively stabilized with fewer spikes during off-peak hours. There is no clear downward trend in price volatility during the peak hours. In the following, we explore the trend of regional prices and price volatility in more details.

4.1 Rolling Correlation Coefficient

We start with a simple analysis of correlation between load zone prices. The 30-day rolling window correlation coefficients between any two of the four ERCOT regions are calculated. The re-

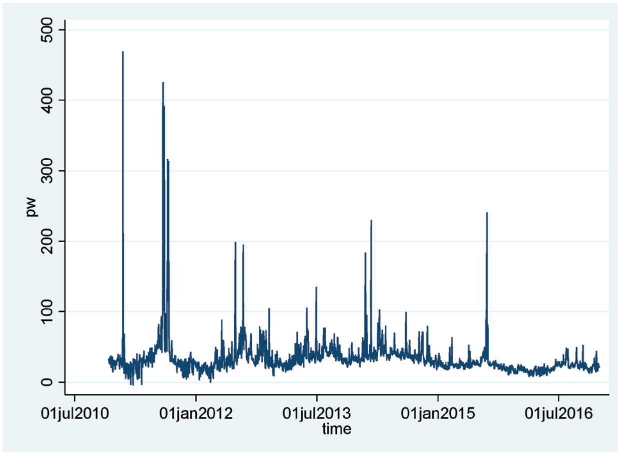
7. We thank Zheng Xu for his help in data collection.

8. The price for load zones in day-ahead market is "the load-weighted average of LMPs at electrical buses in load zone" (http://www.ercot.com/content/wcm/training_courses/101/trn101_m1_120313.pdf). It is based on a broader set of transmission lines compared to trading hub prices, which are based on selected 138KV and 345KV transmission lines. We thank an anonymous reviewer for pointing this out.

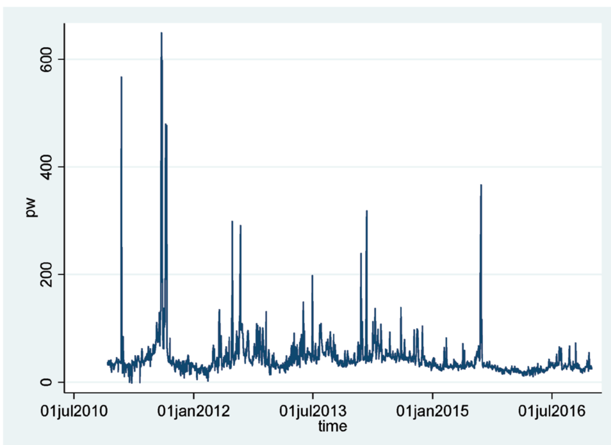
9. Specifically, these days are 3/13/2011 (23 price observations), 11/6/2011 (25 observations), 3/11/2012, 11/4/2012, 3/10/2013, 11/3/2013, 3/9/2014, 11/2/2014, 3/8/2015, 11/1/2015, 3/13/2016, and 11/6/2016.

10. January 2012 is chosen as initial major transmission lines from the West were energized in February 2012 and thereafter.

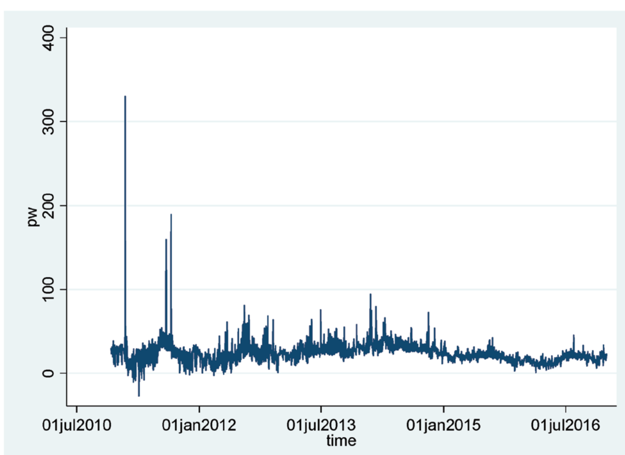
Figure 2: Daily Prices of the West Region in the Day-Ahead-Market (Pw), 12/1/2010-12/31/2016



(a) Daily average price



(b) Daily average price of peak hours



(c) Daily average price of off-peak hours

Table 1: Summary Statistics of Day-Ahead Regional Wholesale Prices

	Obs.	Mean	Std. Dev.	Min	Max
Daily average					
Houston	2,223	31.40	24.39	10.14	426.94
North	2,223	30.70	24.99	10.69	464.21
South	2,223	31.96	25.36	9.59	461.82
West	2,223	33.65	27.40	–3.98	468.84
Daily peak average					
Houston	1,554	40.46	41.61	14.25	642.97
North	1,554	39.36	42.58	15.13	645.09
South	1,554	41.72	43.02	15.78	643.34
West	1,554	45.27	45.76	–1.91	649.02
Daily off-peak average					
Houston	2,223	24.12	10.88	4.50	303.77
North	2,223	23.87	10.94	4.32	312.20
South	2,223	24.13	11.34	4.53	317.75
West	2,223	23.54	13.58	–27.12	330.30

West	# negative prices 12/2010–12/2011	# negative prices 01/2012–12/2016
Daily average	3	0
Daily peak	3	0
Daily off-peak	15	3

Note: There are 0 negative prices in the other three regions before and after January 2012.

sults on daily off-peak prices are presented in Figure 3. For daily average and peak prices, the results of which are available upon request, the correlation coefficients exhibit a similar but noisier trend.

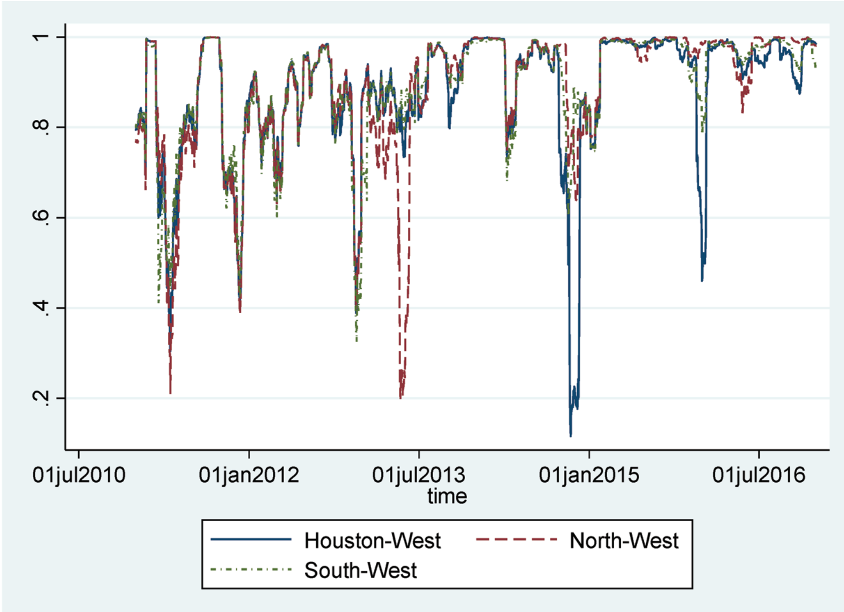
Panel (a) of Figure 3 presents the rolling correlations between the West and three other regions and Panel (b) includes those between the regions of the North, South and Houston. Despite several spikes in the early period, the correlation in panel (a) shows an increasing trend till the mid of 2013 and stays in high level of above 0.9 afterwards. The timing is in general consistent with the construction and progress of the CREZ transmission lines. The high correlations between the West and other three regions indicate a gradual integration among the regional markets. On the other hand, the correlations between the South, North and Houston markets stay close to 1 throughout the whole sample period and didn't go through the changes illustrated in panel (a). This tells us that the CREZ lines contribute most to the connection between the West and other regions due to the transmission of wind, while the other three regions are probably well connected from the beginning. After June 2013, the patterns of price correlation in both panels are similar to each other indicating a better integrated ERCOT market. The sudden drop in correlations in Figure 3 around the end of December 2015 corresponds to the weather and climate disaster known as "Texas Tornadoes and Midwest Flooding" that costs around $2.1 billion.[11]

4.2 Structural Break Test of Relative Prices

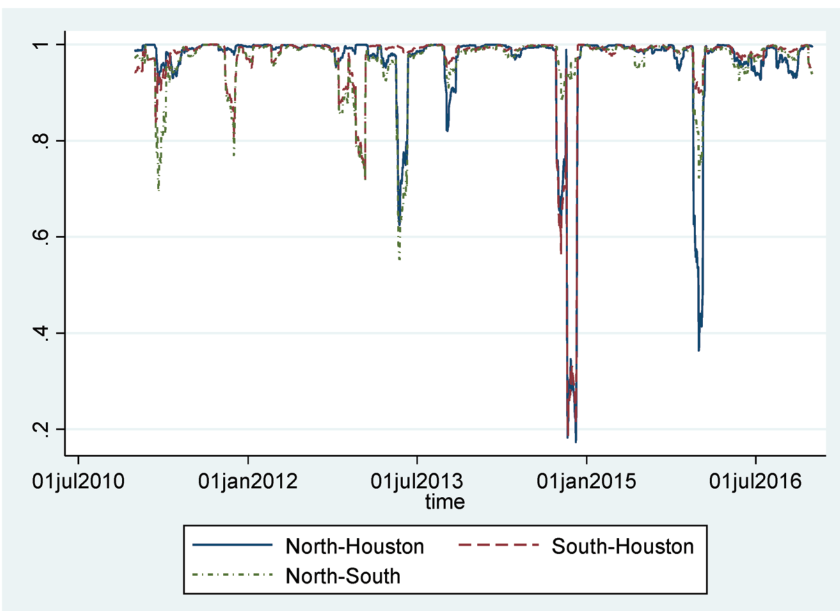
Rolling-window correlation coefficients discussed above illustrate an integration process of load zone prices. To identify the exact timing of the process, we apply the Bai-Perron structural break test (Bai and Perron 1998, 2003) on the pair-wise relative prices. We focus on the relative prices between the West and the other three regions where the transition mainly happened. The

11. For details about this disaster see https://www.ncdc.noaa.gov/billions/events.pdf.

Figure 3: 30-Day Rolling Window Correlation Coefficients, 12/1/2010–12/31/2016



(a) Rolling correlations between West and other ERCOT regions.



(b) Rolling correlations between other regions except the West.

Note: Prices are daily regional off-peak prices.

results on the relative prices between the North, South, and Houston, which are available upon request, will also be discussed briefly.

First we apply the Augmented Dickey-Fuller unit-root tests (ADF) on all relative price series of daily average, peak and off-peak hours. The null hypotheses that an individual relative price series contains a unit root are all rejected at 1% significance level with various numbers of lagged terms of 1 to 6. It indicates that all prices follow a stationary process. The relative daily average price series are presented in Figure 4. Visual inspection of the price series indicates a convergence process that the price differences gradually decrease till the mid of 2013 and stay close to 0 after that. This is consistent with what we find in the correlation changes in the previous section and the approaching completion of the CREZ project.

The Bai-Perron structural break test is implemented based on the multiple linear regression with m unknown breaks, which is specified as: $y_t = z_t{}'\delta_j + u_t$, $t = T_{j-1}+1,...,T_j$, where $j = 1,...,m+1$ are the corresponding $m+1$ regimes.[12] The dependent variable, y_t, is the regional relative price at time t. For the right hand side variables, we include only the constant term without other control variables, i.e., we capture only the mean shift of the process. This is also the so-called pure structural change model in Bai and Perron (2003). The break points are estimated as the global minimizers of the sum of squared residuals, $(\mathrm{Y} - Z\delta)'(Y - Z\delta)$. The test for the number of breaks and corresponding break dates can be conducted sequentially by comparing the sum of squared residuals between the models with l and $l+1$ breaks.[13]

The results of the break tests are reported in Table 2. The corresponding timing of the structural breaks are also indicated in Figure 4 for the relative daily average prices and in Figure 5 for the relative off-peak prices. For both the daily average and off-peak prices, we see a structural break on March 19, 2012. From the CREZ construction progress map (Figure 6), this corresponds to the finishing time of the connection between Tonkawas-Sweetwater East-Central Bluff-Bluff-Creek (from June 2011 to February 2012). This is the period before the commissioning of all other major connection lines between the West and the other regions. So we treat the period of December 2010 to March 2012 as the pre-integration period.[14]

In Figure 5, we see that the second break point is identified around the end of October 2014 for the pairs of Houston-West and North-West and early January of 2015 for South-West, although the period is identified as the break only for the North-West in the daily average prices (Figure 4b). Figure 5 shows that moving from this point forward, all the relative prices are close to 0, or the prices are converged. This is consistent with the timing of the CREZ project. By that time, the major connections between the West, North and South are done. For example, with the lines of W. Krum-Anna and Clearcrossing-Rocky Mound-Henderson, both of which were commissioned in December 2013, the transmission of Alibates (West) to the North is fully connected. Another connection between the West and South, Long Draw-Sand Bluff-LDivide was also finished by December 2013. So we take the period after October 2014 as the after-integration period.[15] The period between April 2012 and October 2014 is treated as within-transition period when some important connections were

12. This is a simplified version of eqn. (1) in Bai and Perron (2003).

13. See more computational details in Bai and Parron (2003). The Matlab code is publicly available at http://people.bu.edu/perron/code.html.

14. It should be noted that 2011 was not a regular year in terms of weather conditions in Texas. In early February 2011, extreme cold weather led to a grid emergency, curtailment events, and prices remained at capped levels for numerous hours. Later that year, a heat wave in August led to additional price spikes. These events are apparent when looking at electricity prices in the West (Figure 2). More generally, annual prices were higher than usual. The average day-ahead price in 2011 was $46 compared with $42 in 2010 (under zonal pricing regime till December) and $29 in 2012 (Potomac Economics 2013). However, it is important to note that electricity prices were relatively high all around ERCOT, hence we do not expect 2011 to impact much the cross-regional analysis and our conclusions. We thank an anonymous reviewer for raising this point.

15. Although the CREZ project was completed by the end of January 2014, it took a bit longer for the whole system to converge as the load zone prices represent market-wide condition. The end of transition break is identified at an earlier date using trading hub prices, which indicates the convergence of LMPs at major transmission lines. The results are available upon request.

Table 2: The Bai-Parron Structural Break Test Results (95% Confidence intervals are in parentheses)

	Daily average price		Peak price		Off-peak price	
	Break points	Break dates	Break points	Break dates	Break points	Break dates
HW	484 (423,498)	03/19/2012	339 (287,347)	03/27/2012	475 (439,539)	03/19/2012
	1048 (1008,1245)	09/25/2013	721 (664,866)	09/25/2013	1426 (1378,1790)	10/26/2014
	1735 (1719,1864)	07/30/2015	997 (987,1467)	10/24/2014		
			1245 (1221,1260)	10/14/2015		
NW	484 (429,495)	03/19/2012	339 (294,345)	03/27/2012	475 (436,535)	03/19/2012
	1076 (957,1365)	10/22/2013	737 (671,884)	10/17/2013	1426 (1422,2705)	10/26/2014
	1456 (1453,1959)	10/30/2014	998 (996,1347)	10/27/2014	1797 (1744,1914)	11/01/2015
	1812 (1794,1865)	10/14/2015	1245 (1232,1285)	10/14/2015		
SW	484 (427,505)	03/19/2012	339 (289,353)	03/27/2012	475 (441,533)	03/19/2012
	1076 (1020,1236)	10/22/2013	710 (641,884)	09/10/2013	1503 (1503,1953)	01/11/2015
	1749 (1736,2007)	08/13/2015	944 (854,1053)	08/11/2014		
HN	904 (334,1038)	05/05/2013	No Break	—	900 (322, 968)	05/18/2013
HS	No break	—	No break	—	No break	—
NS	No break	—	No break	—	No break	—

Note: The results are estimated based the sequential procedures at the 1% significance level. For peak price of SW, the results of the 2.5% significance level are reported due to the different number of breaks estimated by the sequential and global optimization methods (see Bai and Perron (1998, 2003) for details of the estimation methods).

finishing. To quantify to what extent the regional markets are integrated before and after the CREZ project, a structural vector autoregressive model is estimated for the before- and after-integration periods separately, which will be discussed in details in the next section.

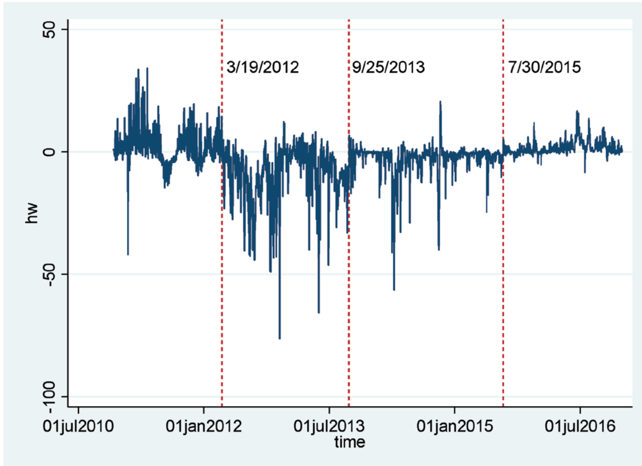
4.3 SVAR

As discussed above, prices of the regional markets in ERCOT went through a gradual transition process toward convergence and an integrated market, the timing of which is consistent with the construction of the CREZ transmission lines. For empirically quantifying the impact of price shocks across load zones, especially the related changes before and after the CREZ project, we implement the SVAR model of the load zone prices as follows:

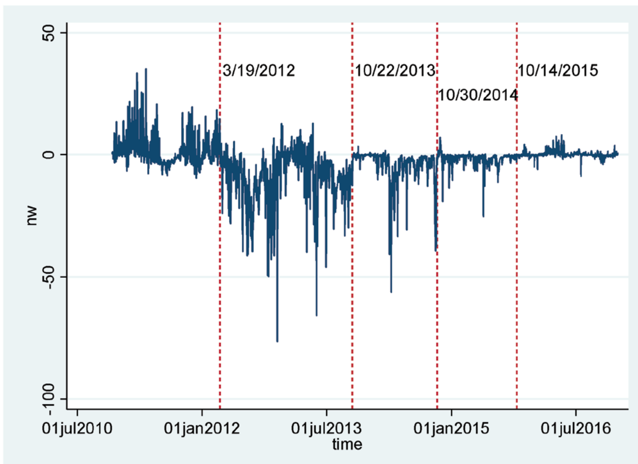
$$\begin{aligned} AY_t &= \sum\nolimits_{j=1}^{J} C_j Y_{t-j} + \varepsilon_t, \\ E(\varepsilon_t) &= 0,\ E(\varepsilon_t \varepsilon_t') = \Sigma_\varepsilon. \end{aligned} \tag{1}$$

where $Y_t = [P_t^W\ P_t^N\ P_t^S\ P_t^H]'$ denotes the average prices during off-peak hours in the West, North, South, and Houston regions, respectively. We focus on the off-peak prices here because that while

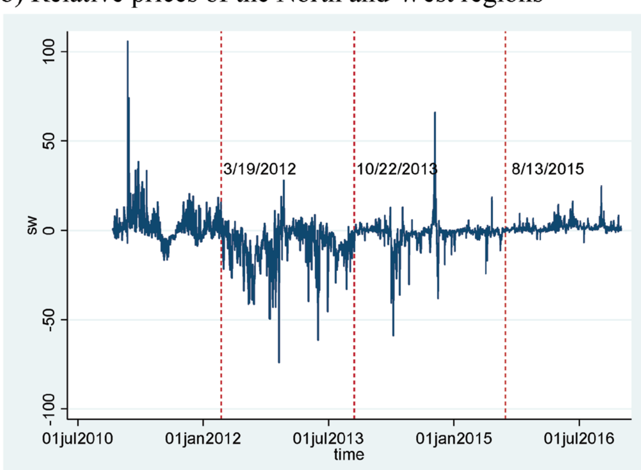
Figure 4: Relative Daily Average Prices Between the West and Other Three Regions, 12/1/2010–12/31/2016 (vertical lines are structural break points)



(a) Relative prices of the Houston and West regions

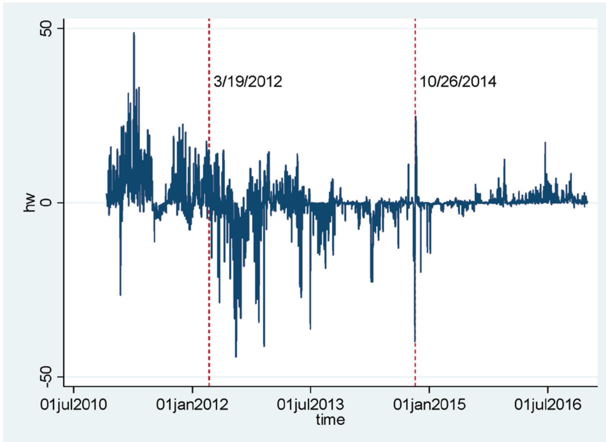


(b) Relative prices of the North and West regions

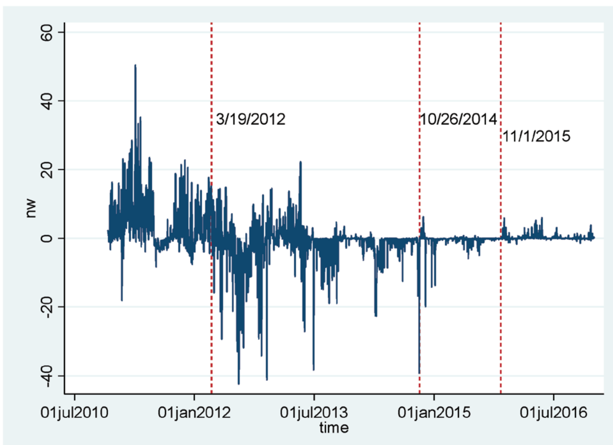


(c) Relative prices of the South and West regions

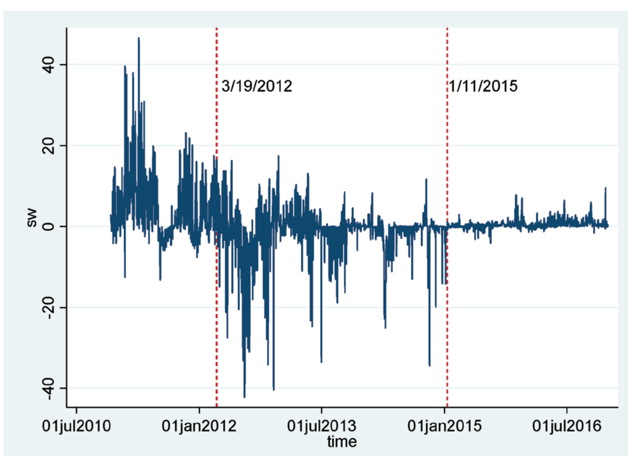
Figure 5: Relative Off-Peak Prices Between the West and Other Three Regions, 12/1/2010–12/31/2016 (Vertical lines are structural break points)



(a) Relative off-peak prices of Houston and West regions

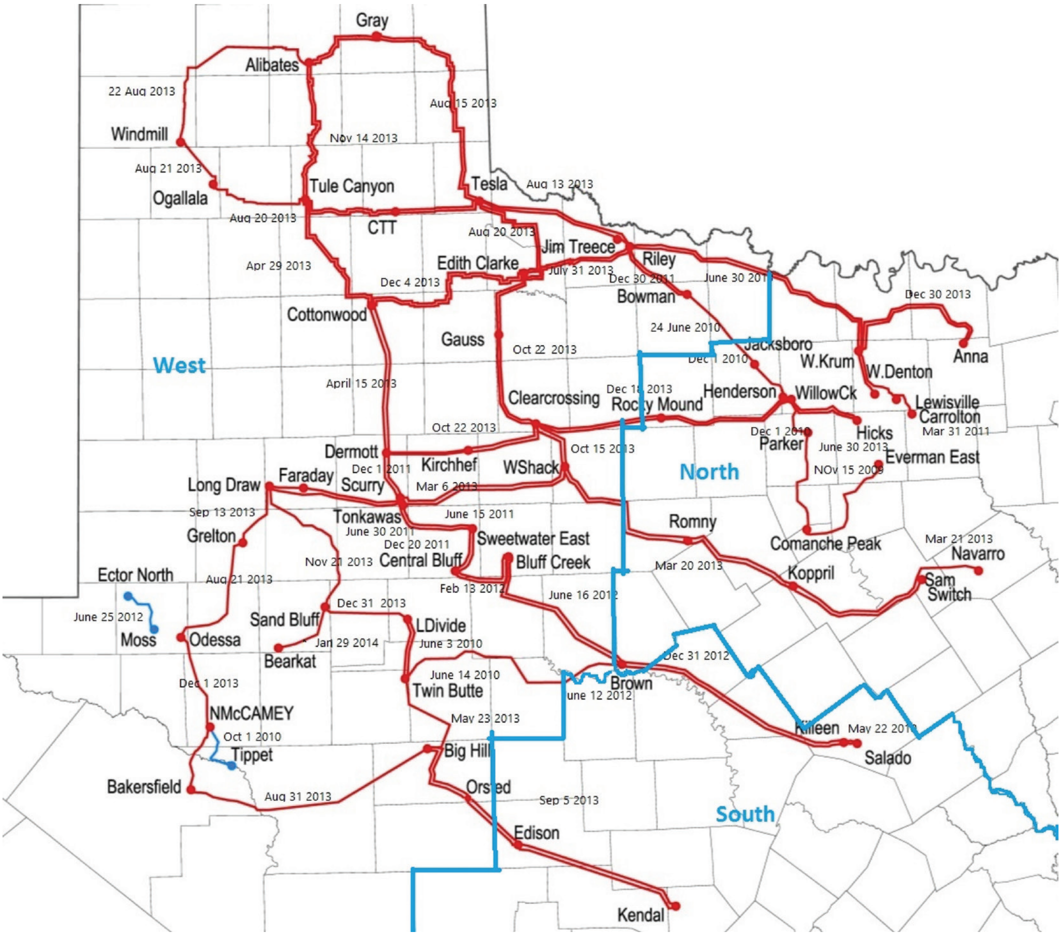


(b) Relative off-peak prices of North and West regions



(c) Relative off-peak prices of South and West regions

Figure 6: CREZ Transmission Projects by Completion Date.



Authors reproduction from ERCOT (2014) and TransmissionHub articles.

wind is typically available during off-peak hours, the CREZ connections contribute to the price convergence mainly in these hours. In other words, before and after the CREZ project, we should expect more changes in prices during the off-peak hours. The matrix A characterizes the contemporaneous relationships among the prices. The matrix C_j $(j = 1,...,J)$ indicates the effects of the lagged endogenous variables, the length of which is denoted by J. The vector ε_t contains the structural errors with mean 0 and variance-covariance matrix of Σ_ε, which can be normalized to be the identity matrix without loss of generality, i.e., $E(\varepsilon_t \varepsilon_t{}') = \Sigma_\varepsilon = I_\varepsilon$.

Assume that A is invertible, the SVAR model can be rewritten in the reduced form as:

$$Y_t = \sum\nolimits_{j=1}^{J} A^{-1} C_j Y_{t-j} + A^{-1}\varepsilon_t \equiv \sum\nolimits_{j=1}^{J} B_j Y_{t-j} + \zeta_t \tag{2}$$

where $B_j = A^{-1}C_j$ and $\zeta_t = A^{-1}\varepsilon_t$ with variance-covariance matrix $E(\zeta_t \zeta_t{}') = \Sigma_\zeta = A^{-1}A^{-1}{}'$. For identifying the SVAR system, specifically the n^2 elements of the matrix A, we only have the information of Σ_ζ estimated from the reduced form VAR model, the dimension of which is $n(n+1)/2$ given the symmetric covariance matrix. So in our case, we need $n(n-1)/2$ identifying assumptions, or 6 assumptions on the 4×4 matrix of A. We impose the symmetry constrains on the matrix A, i.e., $A_{ij} = A_{ji}$.

This means that the response of market *i* to price changes in market *j* is the same as the response of *j* to those of *i*. The symmetry response assumption should be valid given that connectivity goes both ways, i.e. theoretically, if it was the other way around, *Ceteris paribus,* the mutual effect on markets, would have been the same.

The SVAR model is estimated separately on the samples before and after the transition associated with CREZ.[16,17] As indicated in Figure 5, before-transition refers to the period of December 1, 2010-March 19, 2012 and after-transition covers the period of October 26, 2014-December 31, 2016. Following the test statistics of the Schwarz's Bayesian information criterion (SBIC), we choose one as the optimal lag length, i.e., only the first lag of Y_t is included in the model for both before- and after-transition.

We move forward to analyze structural impulse response functions. These functions describe the movement of each series in our SVAR model in response to a one-time shock in each series. This strategy has been used extensively to analyze price dynamics in electricity markets (e.g., De Vany and Walls 1999; Park et al. 2006; Le Pen and Sévi 2010; Karanfil and Li 2017). The functions mimic market price shocks that may be triggered by various reasons, including generators outages, system failure, shortage in the supply of input factors, and extreme weather conditions.

Figure 7 presents the structural impulse response for 20 periods of the prices in the three load zones, North (P_N), South (P_S) and Houston (P_H), to a one-percentage-point increase in the price of the West (P_W) for the before-transition period (Period I; the left column) and the after-transition period (Period II; the right column).[18] The shaded bands represent the 95 percent confidence intervals of the responses. We start with the left column. An unanticipated disruption in the West reduces the prices of the North and Houston by about 1.5–3 percent immediately. After that the prices gradually increase, and the impact of the initial shock vanishes after about 10 days. The response of the South is different where the first step response is 1 percent above 0, then declining to about 0.7–0.8 percent lower, and gradually increases thereafter.

The right column of Figure 7 also shows the responses to the one-percentage-point price shock initiated in the West, but after the transition. The responses are markedly different from what are on the left. The shock leads to 2.0–2.5 percent increases in all three regions. Then the impact gradually declines and remains positive till about 10 days after the shock. This is consistent with the hypothesis that with the CREZ transmission lines in place, regional markets are well integrated, which is illustrated by the strong co-movement of the prices in the connected although geographically separated markets.

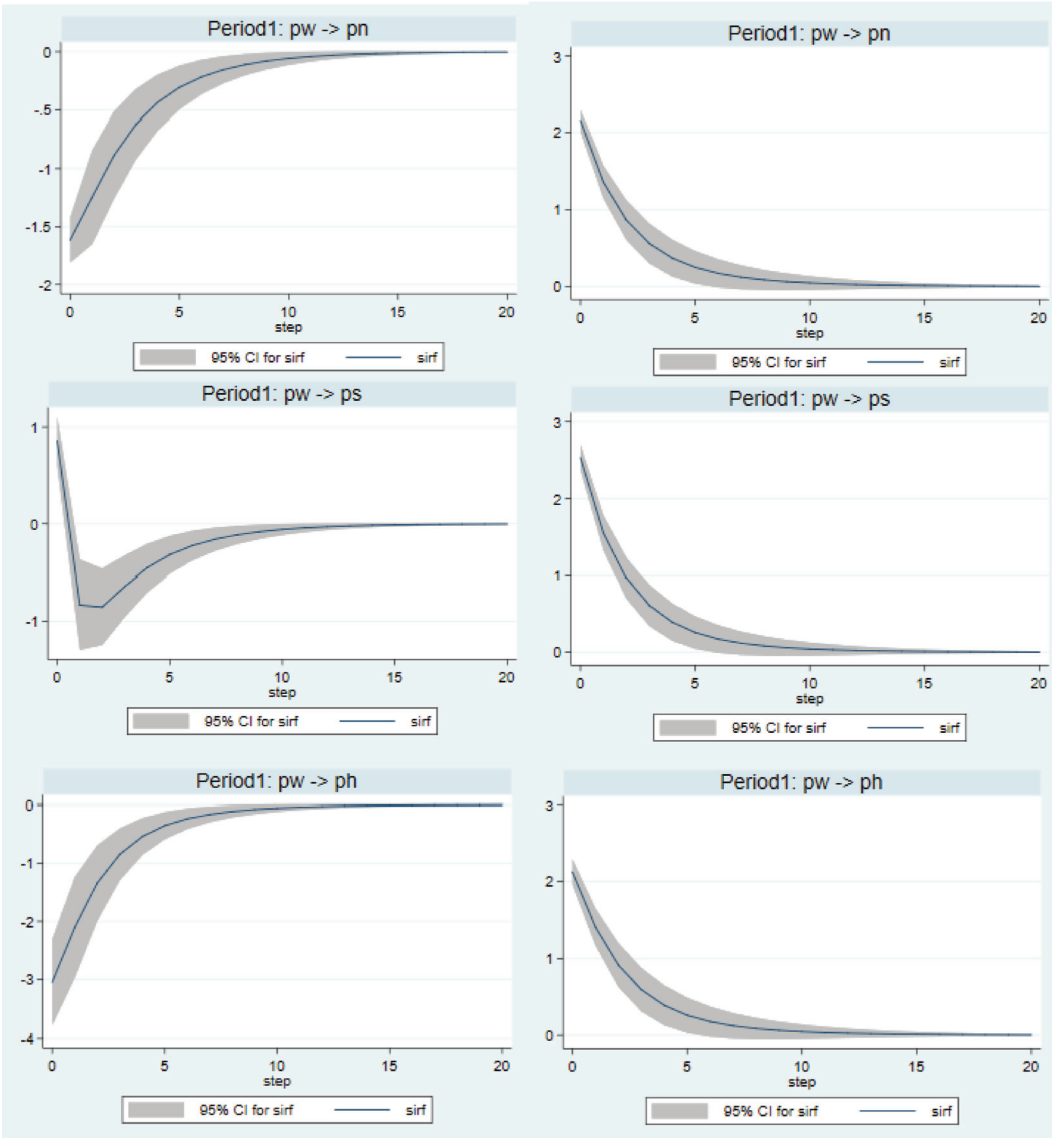
Table 3 reports the portion of the forecast error variance of regional prices at the 1-, 10-, and 20-day horizon that attributes to individual structural shocks (in the first column). This tells us the importance of specific shocks in driving price changes in other regions before (Column II-V) and after transition (Column VI-IX). Let's look at the West region first by comparing the results in Column II with Column VI. Before the transition, as shown in Column II, about 10.0%–12.1% of the price fluctuation in the West can be explained by the shocks originated by its own. North is the most important driver for the forecast error variation contributing about 85.4%–87.7% of the total, depending on the forecast horizon. In general, higher the contributing portion of the West and Hous-

16. For SVAR estimation of the off-peak prices, prices above 50 and below –50 are treated as outliers and excluded from the sample.

17. We thank Miguel Dorta of StataCorp for helping us implement the estimation procedure.

18. For the before-transition period, the SVAR system converges to multiple local maxima with the same log-likelihood values, which indicates the presence of noise and local instability. We report here the set of results that are consistent with those discussed in the robustness check for the before-transition period.

Figure 7: Structural Impulse Responses (impulse: P_W; responses: P_N, P_S, P_H)



ton and lower of the North when moving further into the horizon. After the transition as shown in Column VI, or after October 26, 2014, the price shocks in the West are largely driven by the shocks in its own and the Houston region that explain the forecast error variance in the West, 62.8%, and 22.4%, respectively, for the 20-day ahead forecast.

The North and South regions share a similar trend that the contribution of the shocks in the West and Houston increases after the transition. For example, for the 20-day forecast horizon, the portion of forecast error of P_S can be explained by the shocks of P_W increases from 6% before (Column IV) to 35.2% after (Column VIII). Correspondingly, increased from 3.9%, 31.9% of the forecast error variance can be explained by the shocks in P_H after the transition**.** For the Houston region, we see a significant increase of the West's contribution to the price variation, from 10.8% to 24.9% for the 1-day ahead and 13.2% to 23.6% for the 10- and 20-day ahead forecast horizon.

For robustness check, we control the natural gas prices and ERCOT load in the individual price equations of the SVAR system.[19] The gas prices are Henry Hub spot prices maintained by EIA (Energy Information Administration).[20] The daily off-peak load of ERCOT is constructed from hourly load data requested from ERCOT. The system wide demand of the ERCOT is used as we are concerned about the endogeneity of regional level demand if they are included in individual price equations. The results of impulse-response and forecast error variance decomposition are included in the Appendix. The responses of all other regions to the one-percentage-point price shock in the West are similar to the findings above, except that before the transition, the responses are much larger (around 10–13%) and much shorter (about 5 days), while those of after transition are relatively smaller (1–1.5%) compared to what is reported in Figure 7. It makes sense because the system is more volatile and less stable before the transition. But when the system is well integrated, relative smaller responses are expected when some variations are captured by the changes in natural gas prices and system wide demand.

Before the transition, the results of the forecast error variance decomposition in the Appendix are quite different from what is reported in Table 3 without price and demand controls. The shocks of the West and South dominate price variations in all regions and the contribution of the Houston market is small, about 7% for the West and slightly above 10% for the other three including itself. With the CREZ in place, the regional specific demand shocks in Houston contribute more significantly to the price variations in the West, North, and South. Another big difference is that after controlling for system load and gas prices, prices variations of the North and South load zones are more evenly driven by the shocks of other regions. The contribution of the Houston to the West increases from 6.9% to 23.3%. All of these indicate a better integrated ERCOT market.

To conclude our findings from the structural forecast error variance decomposition, it is shown that upon the completion of the CREZ, the prices of the North and South regions are strongly driven by the supply and demand shocks originated in the West and/or Houston markets, while the price of the West is increasingly driven by the demand shocks generated in the Houston region.

4.4 Daily Price Volatility

So far we have been focusing on the CREZ impact on the levels of load zone prices. In this section, we seek to understand the CREZ related changes of price volatility. We construct a range-based daily volatility measure. It is shown in the literature that the volatility measure constructed from price ranges is efficient and robust to microstructure noise (Alizadeh, Brandt and Diebold 2002). Its accuracy is similar to the intraday sample variance calculated from 2–3 hourly returns (Andersen and Bollerslev 1998). Specifically, the price volatility of day t in market i is constructed as the log of the price range of the day, i.e., $\mathrm{y}_{it} \equiv \ln(P_{ih}^{\max} - P_{ih}^{\min})$. For all hours in a given day (i.e. 24 hours except days of clock adjustment for the daylight saving time), the corresponding volatility measure is called daily average volatility as the price range is calculated from all hours. For peak (or off-peak) hours, the constructed measure is daily peak (or off-peak) volatility when the range only covers peak (or off-peak) hours of a day following the ERCOT definition. We make the distinction of the three volatility measures to fully understand the impact of the CREZ on price volatility in both peak and off-peak hours. While daily average volatility captures the overall effect, it is necessary to quantify the different impact across peak and off-peak hours given the fact that the focus of the CREZ project is to transmit wind generated electricity, which is mostly available in off-peak hours, to demanding areas.

19. We thank an anonymous reviewer for pointing this out.
20. The data is available at: https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm (accessed 2/22/2018).

Table 3: Structural Forecast Error Variance Decomposition (SFEVD) (standard errors are in parentheses)

	Before-transition				After-transition			
Shocks	P_W	P_N	P_S	P_H	P_W	P_N	P_S	P_H
1 day ahead								
P_W	10.0	12.9	2.7	10.8	65.1	34.3	39.9	24.9
	(1.7)	(1.6)	(0.9)	(2.7)	(1.8)	(1.4)	(1.5)	(1.5)
P_N	87.7	85.0	90.4	30.9	4.5	18.5	7.8	5.2
	(1.9)	(1.8)	(1.5)	(3.3)	(0.3)	(1.0)	(0.4)	(0.4)
P_S	0.3	1.3	1.5	2.7	6.5	9.7	19.5	5.6
	(0.09)	(0.2)	(0.4)	(1.0)	(0.4)	(0.5)	(1.0)	(0.4)
P_H	2.0	0.9	5.4	55.6	23.8	37.6	32.7	64.3
	(0.5)	(0.2)	(1.8)	(3.5)	(1.4)	(1.4)	(1.4)	(1.8)
10 days ahead								
P_W	12.1	14.0	6.0	13.2	62.9	28.9	35.2	23.6
	(2.9)	(3.0)	(2.2)	(3.4)	(3.5)	(3.1)	(3.1)	(2.9)
P_N	85.4	82.9	86.1	35.8	10.2	31.2	18.8	19.2
	(3.1)	(3.2)	(2.2)	(4.4)	(2.7)	(3.8)	(3.4)	(3.6)
P_S	0.6	1.7	4.0	4.5	4.5	6.2	14.1	4.3
	(0.8)	(1.2)	(1.8)	(2.0)	(0.5)	(0.7)	(1.5)	(0.7)
P_H	1.9	1.4	3.9	46.6	22.4	33.7	31.9	52.9
	(1.2)	(1.3)	(1.5)	(4.5)	(2.6)	(3.1)	(2.8)	(3.4)
20 days ahead								
P_W	12.1	14.0	6.0	13.2	62.8	28.9	35.2	23.6
	(2.9)	(3.0)	(2.2)	(3.4)	(3.5)	(3.1)	(3.1)	(2.9)
P_N	85.4	82.9	86.1	35.8	10.2	31.3	18.9	19.3
	(3.1)	(3.2)	(2.9)	(4.4)	(2.7)	(3.9)	(3.5)	(3.7)
P_S	0.6	1.7	4.0	4.5	4.6	6.2	14.1	4.3
	(0.8)	(1.2)	(1.8)	(2.0)	(0.6)	(0.7)	(1.5)	(0.7)
P_H	1.9	1.4	3.9	46.5	22.4	33.7	31.9	52.8
	(1.2)	(1.3)	(1.5)	(4.5)	(2.6)	(3.1)	(2.8)	(3.4)

To quantify the volatility changes over the transition period, we use the price differences between the West and Houston presented in Figures 3 and 4 as the proxy for the progress of the CREZ project. So for daily average volatility, the price differences are calculated as the difference of daily price averaged over 24 hours; for peak (or off-peak) volatility, the differences are based on daily price averaged over peak (or off-peak) hours. The empirical model is specified as follows:

$$y_{it} = \sum_{l=1}^{L} \beta_l y_{i,t-l} + \gamma Z_{it} + \varepsilon_{it} \tag{3}$$

The lagged dependent variables, $y_{i,t-l}$, of region i in length l ($l = 1,\ldots,L$) capture the dynamics of the daily volatility. In our case, we include 2 lags, i.e., an AR(2) model. Other control variables in Z_{it} include the average price volatility in the previous week and the previous month and the relative price between the West and Houston. So in eqn. (3), the volatility depends on lagged daily, weekly and monthly volatility in addition to the proxy of the CREZ induced transition. The estimation results are presented in Table 4.

The results indicate significant positive relation between current price volatility and one-day, one-week and one-month lagged volatility except that the monthly lag is not significant in the off-peak equation. The coefficient on the 2-day lagged term is negative in all three regressions, but only marginally significant at 10% level in daily average and peak equations and not significant for off-peak price volatility. More importantly, for both peak and off-peak hours, the price variation

Table 4: Estimation Results of the Daily Price Volatility (standard errors are in parentheses)

	West	North	South	Houston
Daily average				
L(price vol)	0.61***	0.66***	0.68***	0.67***
	(0.02)	(0.02)	(0.02)	(0.02)
L2(price vol)	–0.04*	–0.12***	–0.13***	–0.12***
	(0.02)	(0.02)	(0.02)	(0.02)
L.week(price vol)	0.48***	0.62***	0.61***	0.63***
	(0.04)	(0.04)	(0.04)	(0.04)
L.month(price vol)	0.13***	0.15***	0.16***	0.18***
	(0.05)	(0.05)	(0.05)	(0.05)
H-W price difference	–0.03***	–0.01***	–0.01***	–0.01***
	(0.002)	(0.001)	(0.001)	(0.001)
Constant	1.61***	0.87***	0.88***	0.76***
	(0.20)	(0.16)	(0.17)	(0.16)
Daily peak				
L(price vol)	0.53***	0.59***	0.60***	0.60***
	(0.03)	(0.03)	(0.03)	(0.03)
L2(price vol)	0.05	–0.04	–0.04	–0.02
	(0.03)	(0.03)	(0.03)	(0.03)
L.week(price vol)	0.36***	0.49***	0.47***	0.46***
	(0.05)	(0.05)	(0.05)	(0.05)
L.month(price vol)	0.22***	0.20***	0.22***	0.25***
	(0.06)	(0.05)	(0.06)	(0.06)
H-W price difference	–0.03***	–0.01***	–0.01***	–0.01***
	(0.001)	(0.001)	(0.001)	(0.001)
Constant	1.66***	1.13***	1.17***	1.08***
	(0.24)	(0.21)	(0.22)	(0.21)
Daily off-peak				
L(price vol)	0.39***	0.43***	0.43***	0.43***
	(0.02)	(0.02)	(0.02)	(0.02)
L2(price vol)	–0.34*	–0.37**	–0.38***	–0.38***
	(0.02)	(0.02)	(0.02)	(0.02)
L.week(price vol)	0.78***	0.82***	0.85***	0.84***
	(0.06)	(0.05)	(0.05)	(0.05)
L.month(price vol)	0.01	0.05	0.05	0.05
	(0.07)	(0.06)	(0.06)	(0.06)
H-W price difference	–0.03***	–0.02***	–0.02***	–0.02***
	(0.003)	(0.002)	(0.002)	(0.002)
Constant	0.81***	0.48***	0.39***	0.39***
	(0.20)	(0.14)	(0.14)	(0.14)

decreases with the West-Houston price difference, i.e., lower regional price difference is associated with higher price volatility. This means that after the transition, prices become more volatile in all four regions during both peak and off-peak hours. When an increasing amount of wind energy is incorporated into the system, uncertainty and random fluctuation of wind availability and related energy production require more frequent backup of fossil fuel generations, which pushes up price variation.

5. CONCLUSION

In this paper we utilized the CREZ experience to investigate the market integration of ERCOT. A variety of empirical analyses shows a gradual transition to a well-integrated market. The integration mitigated curtailment and increased the market value of wind, thereby created incentives for investments in remote areas in Texas. Most often, investments in transmission lines and wind energy suffer from the "chicken and egg" problem. While this has been solved by ERCOT via public spending and free access to transmission lines, this is not always the case. Investments can be made by private firms.

There is a growing literature on the allocation of transmission expansion rights and network charges paid by users depending on the benefit allocation (see, e.g., Banez-Chicharro et al. 2017; Hogan 2018; Olmos et al. 2018). But this path may encounter barriers. For instance, Clean Line Energy Partners is a firm that develops new transmission projects in North America. One of them is the Rock Island project which was designed to bring 3.5GW of wind power from Northwest Iowa to Illinois and other states to the east. This $2 billion project has been blocked recently by Illinois Supreme Court due to opposition from landowners and lawmakers. Another project by the same firm is the Grain Belt Express Clean Line, which is planned to deliver 4GW of wind power from western Kansas to Missouri, Illinois, Indiana and neighboring states in approximated cost of $2.3 billion. This project is delayed now by a Missouri court ruling that demands the approval of each individual county along its path. Another example of a large transmission expansion project is the Eversource's Northern Pass proposal that won a preliminary approval from Massachusetts to deliver Canadian hydropower to the state through a transmission line running through New Hampshire.[21] This $1.6 billion, 192-mile project was planned to deliver 1.2GW transmission line to carry hydropower electricity from Quebec through New Hampshire, underground through the White Mountains and out to Massachusetts on the other side. Only one week after the announcement, a unanimous vote by the New Hampshire Site Evaluation Committee, rejected the permit for construction due to high concerns of impacts on land use, tourism, and businesses along its route. These examples illustrate how despite the promise to bring clean and cheap renewable power and creating jobs to communities, transmission projects are often being delayed or completely blocked.

This indicates that quantifying the direct welfare effects resulting from renewable energy integration is much needed, which will be addressed in our future research. For this purpose, investigating price changes alone won't suffice as one should consider structural adjustments that take place in the supply side consequent upon the construction of the transmission project. Such assessment should include production data to measure changes in power generation by capacity type and their costs. The welfare analysis should also include the benefits from displacement of fossil fuel generators and the costs of integrating new wind capacity into the grid.

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APPENDIX

Figure A-1: Structural Impulse Responses after Controlling for Load and Natural Gas Prices (impulse: P_W; responses: P_N, P_S, P_H)

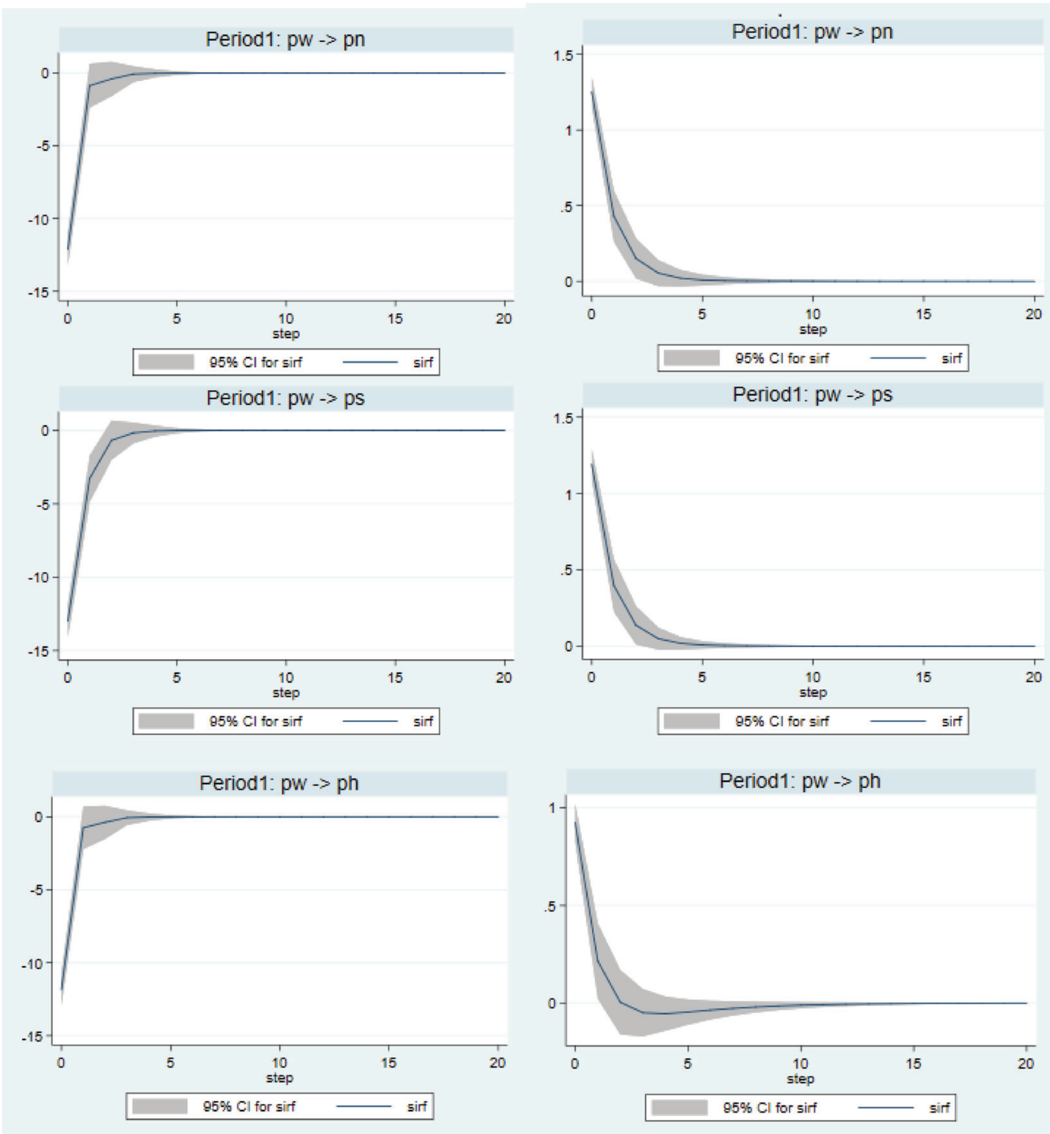

Table A-1: Structural Forecast Error Variance Decomposition (SFEVD) after Controlling for Load and Natural Gas Prices (standard errors are in parentheses)

	Before-transition				After-transition			
Shocks	P_W	P_N	P_S	P_H	P_W	P_N	P_S	P_H
1 day ahead								
P_W	36.8	71.9	78.3	72.0	59.6	30.4	25.1	12.5
	(3.3)	(3.0)	(2.4)	(3.0)	(2.2)	(1.6)	(1.4)	(1.1)
P_N	0.22	1.33	0.09	2.17	6.36	24.4	8.7	3.2
	0.03)	(0.1)	(0.01)	(0.2)	(0.5)	(1.4)	(0.6)	(0.3)
P_S	62.5	22.5	21.4	23.0	9.06	15.0	34.4	5.7
	(3.3)	(2.8)	(2.4)	(2.8)	(0.7)	(0.9)	(1.8)	(0.5)
P_H	0.42	4.19	0.17	2.78	25.0	30.2	31.8	78.6
	(0.05)	(0.4)	(0.03)	(0.3)	(1.7)	(1.7)	(1.7)	(1.6)
10 days ahead								
P_W	31.6	61.6	66.2	62.5	58.6	28.3	25.2	9.7
	(3.2)	(3.9)	(4.0)	(3.8)	(2.8)	(2.2)	(1.9)	(1.1)
P_N	4.55	5.75	3.93	6.19	10.1	31.5	11.5	2.8
	(1.7)	(1.7)	(1.55)	(1.6)	(2.1)	(3.0)	(1.9)	(0.5)
P_S	56.9	19.6	18.3	20.2	8.0	12.8	32.6	5.6
	(3.9)	(2.7)	(2.6)	(2.7)	(0.8)	(0.9)	(2.1)	(1.0)
P_H	6.88	13.1	11.5	11.1	23.3	27.4	30.7	81.9
	(2.5)	(2.9)	(3.2)	(2.7)	(2.0)	(2.1)	(2.0)	(1.8)
20 days ahead								
P_W	31.6	61.6	66.2	62.5	58.6	28.3	25.2	9.7
	(3.2)	(3.9)	(4.0)	(3.8)	(2.8)	(2.2)	(1.9)	(1.1)
P_N	4.55	5.75	3.93	6.19	10.1	31.5	11.5	2.8
	(1.7)	(1.7)	(1.5)	(1.6)	(2.1)	(2.9)	(1.9)	(0.5)
P_S	56.9	19.6	18.3	20.2	8.0	12.8	32.6	5.6
	(3.9)	(2.7)	(2.6)	(2.7)	(0.8)	(0.9)	(2.1)	(1.0)
P_H	6.88	13.1	11.5	11.1	23.3	27.4	30.7	81.9
	(2.5)	(2.9)	(3.2)	(2.7)	(2.0)	(2.1)	(2.0)	(1.8)