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Quantitative Analysis of the Relationship between Energy and Ancillary Services Prices and Quantities

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1. Introduction

The purpose of this paper is to analyze the relationship between energy and ancillary services (AS) as a function of AS requirements. In this study, we utilize the ERCOT day-ahead market. A base case was developed which represents 2008 loads, resources, and transmission topology published by ERCOT's planning group. An alternative case was also prepared in which ancillary service requirements at peak hours were increased by 500 MW.

The Electricity Reliability Council of Texas (ERCOT) is one of ten regional reliability councils under the North American Reliability Council (NERC). ERCOT is also the Independent System Operator (ISO) responsible for grid and market operations in the ERCOT region. Currently, ERCOT has four types of markets: Transmission Congestion Right (TCR) market, Ancillary Service market, Replacement Reserve Service (RPRS) market, and Real-Time Energy Market. TCRs, Ancillary Services, and Energy are traded either bilaterally or in pool markets. Overall, the ERCOT wholesale market is a bilateral and Ancillary Service market with a very small volume spot energy market.

The ERCOT Ancillary Service market runs at Day Ahead. Ancillary Services are self-provided or offered by market participants, and procured and deployed by ERCOT to support the transmission of energy from resource to load while maintaining system reliability. Before 6:00 AM of the Day Ahead, ERCOT will analyze the next day's expected load conditions and develop a Day Ahead Ancillary Services Plan that identifies the amount of each Ancillary Service needed to maintain system reliability for each hour of the next day.

ERCOT allocates Ancillary Service obligations to all participants in proportion to their historic actual load. A participant can self-arrange its Ancillary Service obligation with its own resources or purchase it from other entities through bilateral transactions. If a participant's self-arrangement does not fulfill its obligation, ERCOT will procure the remaining amount on its behalf in the ERCOT Ancillary Service market. ERCOT adopts a simulations clearing method to procure all upward Ancillary Services (URS, RRS, and NSRS) simultaneously to meet its Ancillary Service requirements while minimizing total costs.

2. Study Approach

2.1. Overview

This research presents experience gained from the design and implementation of ERCOT electricity market system. In particular, our focus is on the relationship between energy and ancillary services and corresponding prices.

In practice, energy is the primary commodity of all markets. Based on the priority sequence of market commodities, the sequential approach progressively reduces available capacity of each resource to meet system requirements for each commodity. However, such an approach needs to be able to determine the best tradeoff in sharing limited resource capacity for energy and AS. Our approach is based on formulating simultaneous dispatch problems - which provides improved coordination of energy and AS dispatch to achieve the most secure and economic solution.

Before proceeding with the design and simulation results, it is important to understand the structure of the costs incurred in providing energy and AS requirements. The required AS may be provided by generating units which are online but not fully loaded. The allocation of AS between committed units can be done by selecting a suitable criterion.

LCG used its proprietary UPLAN Network Power Model (UPLAN) to perform this study. UPLAN - utilized in conjunction with LCG's Plants, Loads, AS requirements, Assets, Transmission, and Operations (PLATO) database – is uniquely capable of simulating the ERCOT Texas Nodal Market.

UPLAN can simulate 8,784 hours for the relevant study year. The simulation models the physical and financial characteristics of the entire ERCOT Texas Nodal. The results given by UPLAN are based on hourly nodal prices, generation, load, and AS information for the entire ERCOT grid for the study year. The methodology used in UPLAN is based on a structural modeling of the new Texas Nodal Market by emulating the way the grid operates in the day ahead market where bids and offers, along with market protocols, determine the forward electricity prices.

2.2 The ERCOT Database

For this study, LCG utilized its proprietary ERCOT database. This database has been tested and used for numerous other nodal studies involving LMP forecasts, transmission upgrades, and generation expansion throughout ERCOT.

This database was specifically developed for UPLAN and provides the best estimates of the Generator, Loads, Transmission, Contingencies, SPS, and LMPs for the year of 2008.

The source of this information varies – with different pieces of data being derived from different sources, such as ERCOT planning, historical data, and released public documentation. However, LCG has a dedicated team of experts to ensure that all of the information in its databases is always accurate and thorough.

The transmission network database is derived from official ERCOT transmission planning documents. All buses are assigned a load area and an hourly load profile. In addition, each bus is assigned a percentage of the load area's overall load for each month. The percentage of overall demand assigned to each bus is based on snapshots of ERCOT's demand at each bus. The cogeneration loads and resources are provided by ERCOT.

3. Key Assumptions for Texas Nodal Market Modeling

LCG's proprietary ERCOT database consists of estimates of the generator, loads, transmission, contingencies, SPS, and LMPs for ERCOT. This ERCOT database for the year of 2008 was utilized in conjunction with our UPLAN software model for this study.

3.1 Electricity Demand & AS

For this study, electricity demand – for both annual peak and total annual energy – was projected for each year and each zone as follows.

Table 3-1: ERCOT Demand & Energy Usage: 2008

ERCOT Demand		
Zone	**Annual Peak (MW)**	**Energy (GWh)**
Houston Zone	20,246	120,030
North Zone	27,020	123,579
South Zone	18,370	95,249
West Zone	3,899	22,582
Total	69,535	361,440

Each of these demand zones contains multiple nodes or buses where electricity is either injected by a generator or withdrawn by a distributor, or where there is a transmission junction, such as a major substation.

These load forecasts involve the reserve requirement and a chronological – 8,784 hours for 2008 – load shape developed for each load zone. Chronological load shapes were based on historical profiles available from ERCOT in the ERCOT 5 Year Transmission and System Planning Study.

Monthly AS requirements were specified in terms of a percent of the total load across the control area plus additional fixed MWs for each service. Responsive Reserve peak is assumed to be 3.2%.

3.2 Generation

Over 600 generators, including future expansion units, are characterized in detail in LCG's proprietary ERCOT database and were incorporated into the UPLAN simulations for this study.

Based on the latest generation portfolio updates from ERCOT, the generation projected by fuel type and zone for the year 2008 – as used in this study – can be summarized as follows.

Figure 3-2: ERCOT Generation Capacity by Zone: 2008

ERCOT Capacity by Zone, 2008	
Zone	**MW**
Houston	21,282
North	32,322
South	25,300
West	10,922
Total	89,826

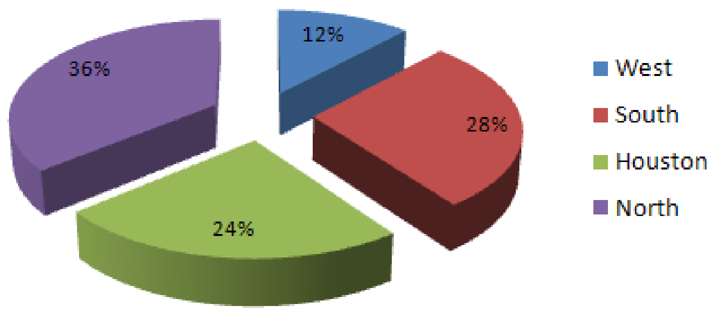
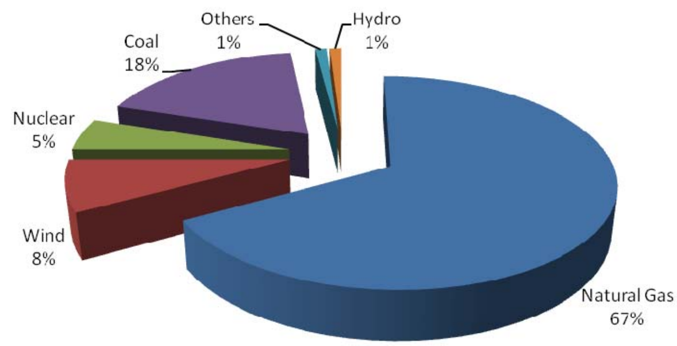


Figure 3-3: ERCOT Generation Capacity by Fuel Type: 2008

ERCOT Capacity by Fuel Type, 2008	
Fuel	**MW**
Natural Gas	59,974
Coal	15,938
Nuclear	4,920
Wind	7,057
Hydro	617
Others	1,320
Total (MW)	89,826



4. Simulation Results

For this study, we simulated two discrete cases based on the ERCOT 2008. We then compared the cases' monthly Energy and Responsive Reserve (RR) prices for the entire year:

The two cases were as follow:

- Case 1: Base Case which represents 2008 loads, resources, and transmission topology published by ERCOT planning group.
- Case 2: An Alternative Case in which ancillary service requirements at peak hours (6:00 am to 10:00 pm) were increased by 500 MW.

Tables 4-1-A and 4-1-B demonstrate the comparison of monthly zonal prices of energy for ON and OFF peak hours.

Table 4-1-A: Comparison of Zonal Price (Energy); 2008
(Average Price in $/MWh, load weighted)

			Base Case			Extra 500 MW RR is added at Peak hours		
Zone Name	**Year**	**Month**	**Off Peak Price**	**On Peak Price**	**Overall Price**	**Off Peak Price**	**On Peak Price**	**Overall Price**
Houston Zone	2008	1	48.12	58.81	53.6	48.4	58.66	53.66
Houston Zone	2008	2	44.48	56.63	50.62	44.28	55.99	50.19
Houston Zone	2008	3	40.64	56.19	48.12	40.6	55.85	47.93
Houston Zone	2008	4	35.29	54.01	45.06	35.41	53.85	45.03
Houston Zone	2008	5	41.04	57.68	49.48	41.24	57.68	49.58
Houston Zone	2008	6	45.07	61.5	53.34	45.12	61.39	53.31
Houston Zone	2008	7	49.61	64.51	57.52	49.59	64.46	57.49
Houston Zone	2008	8	46.99	62.32	54.47	46.96	62.3	54.45
Houston Zone	2008	9	38.49	54.09	46.64	38.28	54.09	46.53
Houston Zone	2008	10	36.52	53.7	45.6	36.45	53.64	45.54
Houston Zone	2008	11	34.81	48.89	41.46	34.95	48.76	41.47
Houston Zone	2008	12	38.43	51.79	45.3	37.93	51.61	44.97
Average	**2008**		**41.62**	**56.68**	**49.27**	**41.60**	**56.52**	**49.18**
North Zone	2008	1	49.9	60.61	55.52	50.12	60.39	55.51
North Zone	2008	2	45.51	59.43	52.75	45.41	58.52	52.23
North Zone	2008	3	40.82	56.48	48.73	40.76	55.85	48.39
North Zone	2008	4	36.39	55.73	47.13	36.42	55.63	47.09
North Zone	2008	5	42.4	60.95	52.32	42.61	60.92	52.4
North Zone	2008	6	47.11	66.62	57.68	47.13	66.64	57.7
North Zone	2008	7	53.46	73.33	64.57	53.39	73.3	64.53
North Zone	2008	8	49.94	69.13	59.85	49.86	68.89	59.69
North Zone	2008	9	39.35	56.73	49.12	39.05	56.55	48.89
North Zone	2008	10	36.93	56.5	47.98	36.88	56.38	47.89
North Zone	2008	11	35.73	48.83	42.11	35.87	48.62	42.08
North Zone	2008	12	39.53	51.76	45.97	39.2	51.7	45.78
Average	**2008**		**43.09**	**59.67**	**51.98**	**43.06**	**59.45**	**51.85**

Table 4-1-B: Comparison of Zonal Price (Energy); 2008
(Average Price in $/MWh, load weighted)

			Base Case			Extra 500 MW RR is added at Peak hours		
Zone Name	Year	Month	Off Peak Price	On Peak Price	Overall Price	Off Peak Price	On Peak Price	Overall Price
South Zone	2008	1	47.6	58.39	53.19	48.03	58.05	53.22
South Zone	2008	2	44.79	56.73	50.9	44.47	55.99	50.37
South Zone	2008	3	41.59	56.17	48.81	41.65	55.92	48.72
South Zone	2008	4	36.17	55.3	46.46	36.38	55.07	46.43
South Zone	2008	5	42.91	58.99	51.26	43.16	59.02	51.4
South Zone	2008	6	46.47	62.53	54.79	46.67	62.48	54.86
South Zone	2008	7	50.49	65.73	58.79	50.52	65.83	58.86
South Zone	2008	8	48.08	63.82	55.93	48.08	63.7	55.87
South Zone	2008	9	38.55	54.3	47.04	38.37	54.18	46.89
South Zone	2008	10	36.66	53.59	45.85	36.66	53.54	45.83
South Zone	2008	11	34.81	48.63	41.46	34.9	48.41	41.4
South Zone	2008	12	38.41	51.44	45.17	38.12	51.09	44.85
Average	**2008**		**42.21**	**57.13**	**49.97**	**42.25**	**56.94**	**49.89**
West Zone	2008	1	48.2	58.36	53.4	48.42	58.29	53.48
West Zone	2008	2	44.13	57.78	51.01	44.16	57.1	50.68
West Zone	2008	3	37.75	54.44	45.83	37.71	53.84	45.52
West Zone	2008	4	33.21	52.72	43.54	33.26	52.5	43.46
West Zone	2008	5	37.03	58.36	48.05	37.29	58.54	48.28
West Zone	2008	6	44.27	66.01	55.51	44.31	66.01	55.54
West Zone	2008	7	52.06	72.51	63.17	51.96	72.47	63.11
West Zone	2008	8	48.33	69.44	58.89	48.18	69.05	58.62
West Zone	2008	9	38.32	57.67	48.64	38	57.47	48.38
West Zone	2008	10	34.38	56.86	46.45	34.38	56.67	46.35
West Zone	2008	11	31.25	43.88	37.22	31.54	43.78	37.32
West Zone	2008	12	35.13	47.16	41.3	35.01	46.84	41.08
Average	**2008**		**40.34**	**57.93**	**49.42**	**40.35**	**57.71**	**49.32**

Table 4-2: Responsive Reserve (RR) Price Summary; North Zone, 2008
(Average Price in $/MWh, load weighted)

	Base Case			Extra 500 MW RR is added at Peak hours		
Month	Off Peak Price	On Peak Price	Overall Price	Off Peak Price	On Peak Price	Overall Price
1	11.16	8.89	9.98	11.24	10.72	10.93
2	9.78	8.25	8.99	10.25	9.07	9.55
3	10.14	7.63	8.9	10.29	9.12	9.61
4	9.78	8.43	9.06	9.45	9.45	9.45
5	8.63	10.08	9.38	8.74	10.98	10.07
6	7.89	11	9.51	7.97	12.65	10.71
7	8.21	12.31	10.45	8.18	14.02	11.71
8	7.1	10.7	8.91	7.14	12.43	10.13
9	9.35	8.42	8.85	9.04	9.57	9.36
10	8.24	8.49	8.38	8.23	9.33	8.91
11	9.39	6.33	7.92	9.21	7.38	8.18
12	12.36	7.9	10.04	12.39	9.8	10.83
Average	**9.34**	**9.04**	**9.20**	**9.34**	**10.38**	**9.95**

These tables reveal that by adding an extra 500 MW RR at peak hours, the energy price decreases. By increasing RR requirements, more units need to be committed to supply both demand and extra RR. When a new unit is added, it runs at least at minimum block and causes a decrease in generation of other units to balance the energy. Therefore, the marginal price of energy will decrease.

In addition, when RR is increased at peak hours, price at other hours changes because of the change in commitment schedule. In other words, sometimes, units need to be committed in advance to be available for peak hours.

As shown in Table 4-2, RR prices increase at ON peak hours. Moreover, while RR prices change at OFF peak hours – sometimes even decreasing - it is not significant compared to ON peak hours.

Table 4-3 compares the summary of two cases. It can be seen that the total cost has been increased in case 2.

Table 4-3: Summary Result

	Base Case	Extra 500 MW RR is added at Peak hours	Difference (Extra RR Case – Base Case)
Total Production Cost (M$)	**14,835.31**	**14,849.42**	**14.11**
Reserve Revenue (M$)	**185.53**	**217.06**	**31.53**
Energy Revenue (M$)	**18,763.90**	**18,729.83**	**-34.07**
Total Reserve & Energy Revenue (M$)	**18,949.43**	**18,946.89**	**-2.54**

5. Conclusions

In this paper, we examine the relationship between energy and Responsive Reserve (RR) costs using an example based on ERCOT day-ahead market. We increased RR by 500 MW at peak hours (7:00 A.M. to 10:00 P.M.) and simulated the market response using UPLAN. The results indicates that increasing RR demand at peak hours increases the price of RR during the peak hours and to some extends during the off peak hours due to the lingering effect of start up and shut down of the generators. This is expected because as the demand for RR increases, additional expensive units have to be committed for supplying the reserve requirement. In this particular case (see Table 4-3), the overall revenues earned by the units supplying the reserve increase by 31.53 million dollars. As extra 500 MW of capacities are committed the overall demand for the energy reduces and there is a corresponding decrease in the energy prices. As a consequence, the energy revenue earned by the generators is decreased by 34.07 million dollars. The total of responsive reserve and energy revenue decrease by 2.54 million dollars whereas the total production cost increases by 14.11 million dollars due to the commitment of more expensive units for reserve. The net cost of improving the reliability of the network is equal to (2.54 plus 14.11) 16.65 million dollars. On the per unit basis, this amounts to $33/kW of additional responsive reserve.