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ANALYSIS OF RESOURCE ADEQUACY— ERCOT SUMMER 2021

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1. INTRODUCTION

LCG Consulting performed an analysis of ERCOT for summer 2021, June through September, using market simulations with LCG's UPLAN Network Power Model. Resource adequacy analysis for the region is critical during extreme summer loading conditions as the reserves have tightened because of recent retirements. The ERCOT landscape is rapidly evolving, with significant transmission changes and unprecedented growth of renewables. This summer follows what may have been the most extreme weather event to ever test the Texas grid, resulting in a much stronger public scrutiny of reliability, as well as new legislation, some still pending resolution.

For this report, LCG built scenarios examining "strained network conditions" that include high generation outages, low wind and high load forecasts. These sensitivity cases were assessed for resource adequacy to see if peak demand is served. This report further identifies strained conditions that might shift expected energy prices, Operating Reserve Demand Curve (ORDC), Peaker Net Margin (PNM), and congestion.

- Scenario 1 or Base Case: Forecasted Season Peak Load (50/50 forecast)
- Scenario 2: High Gen Outages
- Scenario 3: Low Wind
- Scenario 4: High Load

Scenario 1 assumes typical use of reserve capacity conditions while the three other scenarios represent conditions of lower probability. For each of these scenarios, LCG used its UPLAN hourly model to simulate the summer season of 2021. With decades of benchmarking in the ERCOT system, UPLAN accurately captures the operation of the ERCOT system.

2. SCENARIO MODELING & METHODOLOGY

The nodal market simulations were performed using LCG's proprietary UPLAN Network Power Model (NPM) and PLATO-ERCOT data model at the hourly dispatch level. UPLAN authentically replicates the engineering protocols and market procedures of a system operator. Technical details on this sophisticated model are available in the Appendix of the report.

For this study, UPLAN integrates the ERCOT's Steady State Working Group (SSWG) power flow network for summer 2021, with ERCOT standard operational & planned contingencies. Transmission upgrades for summer season were added based on the Transmission Project Information Tracking (TPIT) file, published March 2021. Generation expansion and retirement assumptions rely on ERCOT publications. Monthly peak loads were modified based on the 50/50 forecast published February 2021, while the hourly load shapes use the 2020 RTP Economic Case load profile. Further overview on the UPLAN NPM and PLATO-ERCOT data model can be found in Appendix 1 and Appendix 2, respectively.

Scenario 1 or Base Case: 50/50 Load

In this base case, the peak demand forecast is 77,244 MW, reflecting normal weather conditions based on the ERCOT 50/50 demand forecast, which assumes that there is a 50% probability that the actual peak exceeds the forecast. LCG distributed this load across ERCOT proportional to the nodal Load Distribution Factors (LDFs) published with SSWG network for 2021. The total resource capacity is 86,862 MW, using 80% of rated capacity for solar resources, 61% of coastal installed wind capacity, 19% of non-coastal installed wind capacity, and current seasonal maximum limits of all other units. The reserve capacity is 9,718 MW.

Figure 1 shows the installed capacity by fuel type and Figure 2 shows the installed capacity by load zone. From this resource capacity, 3,617 MW was modeled on forced outages and on maintenance for June through September weekdays. That leaves 6,076 MW of capacity available for operating reserve.

Scenario 2: High Gen Outages

This scenario assumes additional generating capacity of 2,601 MW to be on outage by increasing the forced outage rates of available generating units.[1] With these excess outages, total use of reserve capacity is 6,243 MW and the capacity available for operating reserve falls to 3,475 MW. Other parameters remain the same as in Scenario 1.

Scenario 3: Low Wind

In this scenario, the wind output during the high net load hours is adjusted 6,577 MW downward[2]. Considering this reduction in wind output level, the capacity available for operating reserve is -500 MW. Other parameters remain the same as in Scenario 1.

[1] Based on the 95th percentile of historical forced outages for June through September weekdays, hours ending 3 pm - 8 pm, for the last three summer seasons (2018 -2020), Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Summer 2021, ERCOT

[2] Based on the 5th percentile of hourly wind capacity factors (output as a percentage of installed capacity) associated with the 100 highest Net Load hours (Load minus wind output) for the 2016-2020 summer Peak Load seasons, Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Summer 2021, ERCOT

Scenario 4: High Load

In this scenario, the load adjustment is based on 2011 summer weather conditions and a different economic growth forecast and assumes the peak load of 80,178 MW. ERCOT-wide non-coincidental peak is increased, after which the total use of reserve capacity is 6,576 MW and the capacity available for operating reserve is 3,142 MW. Other assumptions are the same as in Scenario 1.

Table 1 – Range of Potential Risks – Summer 2021 UPLAN Scenario Assumptions

	50/50 Load Base Case	High Outages Scenario 2	Low Wind Scenario 3	High Load Scenario 4
Seasonal Load Adjustment (MW)	-	-	-	2,934
Maintenance Outages, Thermal/Hydro (MW)	25	25	25	25
Typical Forced Outages, Thermal/Hydro (MW)	3,617	3,617	3,617	3,617
Additional Forced Outages, Thermal/Hydro (MW)	-	2,601	-	-
Low Wind Output Adjustment (MW)	-	-	6,577	-
Total Uses of Reserve Capacity (MW)	3,642	6,243	10,219	6576
Capacity Available for Operating Reserves (MW)	6,076	3,475	(500)	3,142

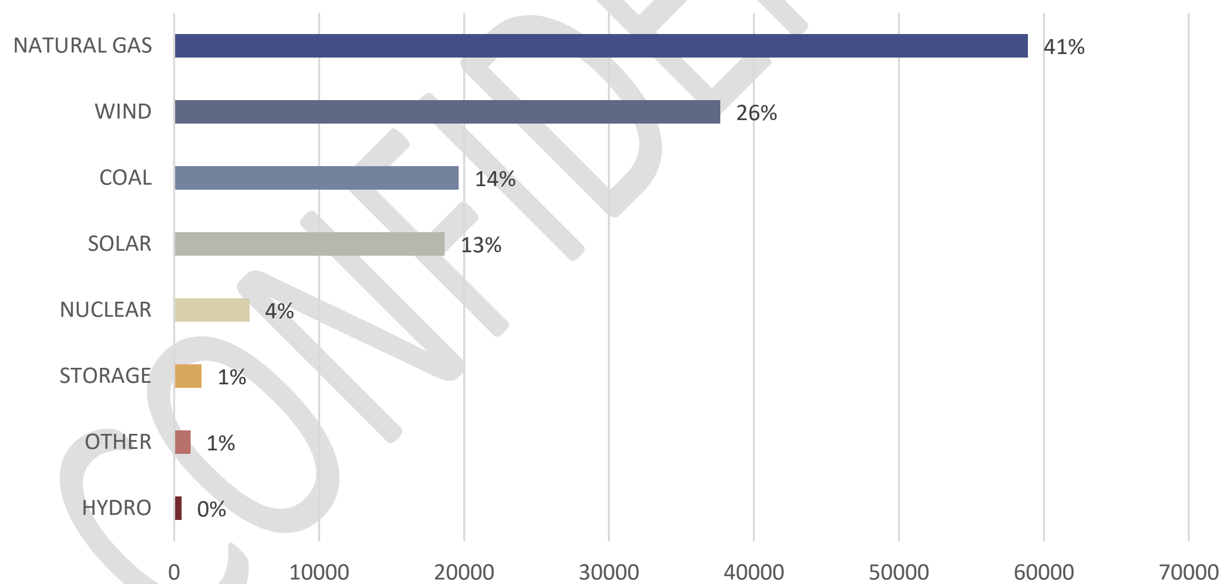


Figure 1 – Installed Capacity by Fuel Type (MW)

Figure 2 – Installed Capacity by Load Zone (MW)

3. SIMULATION RESULTS

3.1 Prices

Load zone prices are highest in the High Gen Outage scenario, where the ERCOT-wide, average, load-weighted price is $52.49, compared to $32.54 in the base case, a 61% increase. The largest price change occurs in the Houston Load Zone, which sees a 72% boost. North Load Zone is the most sensitive to reserve changes in Scenario 3 and 4. In the Low Wind scenario, ERCOT-wide average load-weighted zonal prices increase 17% relative to the Base Case. Average load zone prices for all scenarios are shown below in Figure 3.

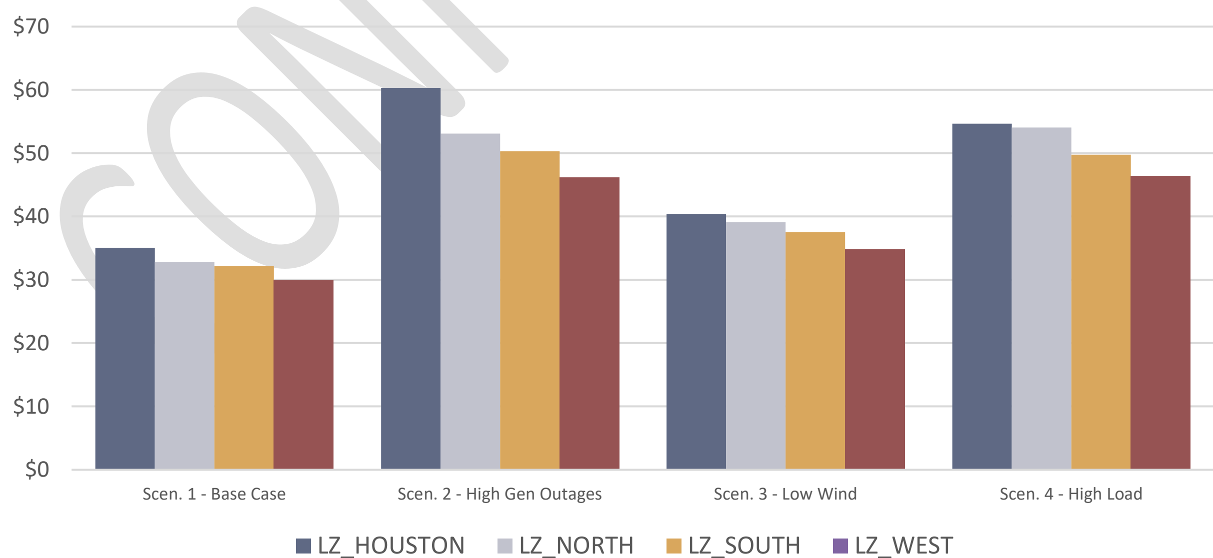


Figure 3 – Average Load-Weighted Zonal Prices by Scenario – Summer 2021 ($/MWh)

For these scenarios, The Houston hub is relatively more sensitive. On average, trading hub prices increase by 47.4% for High Load, by 49.1% for High Outages, and by 13.3% for Low Wind scenarios, compared to the base case average price.

Trading hub price results by scenario are shown below in Figure 4.

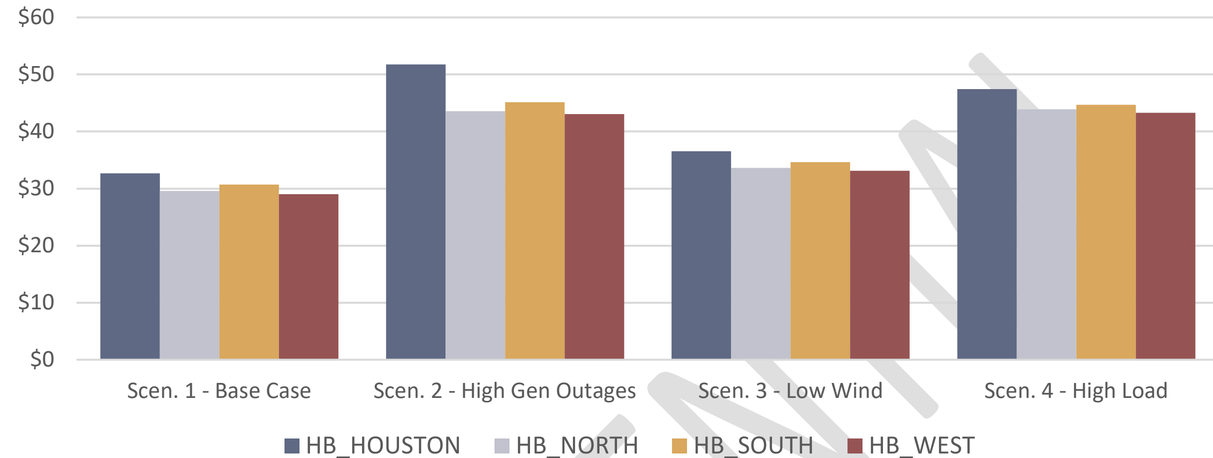


Figure 4 – Average Trading Hub Prices by Scenario – Summer 2021 ($/MWh)

Figure 5 shows the system-wide price duration curve by scenario for the top 100 hours in summer season of 2021. Here it can be seen that there are fewer occurrences of high-priced hours in the Base Case. In both the High Gen Outages and High Load scenarios, there are a few hours of system wide shortage which push the price over the low offer cap of $2000/MWh.

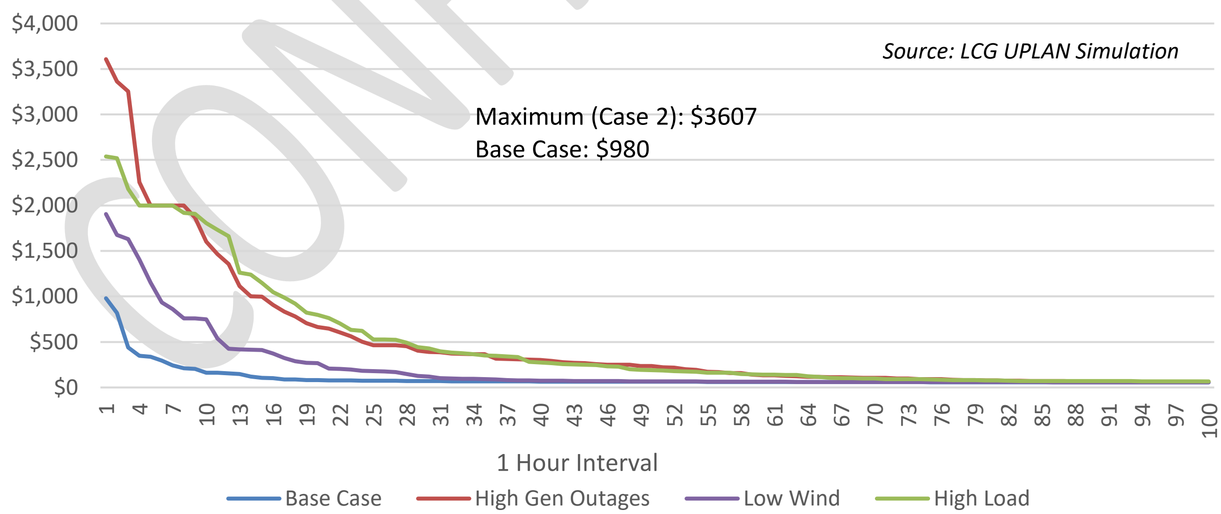


Figure 5 – System-Wide Price Duration Curve - Top 100 Hours – Summer 2021 ($/MWh) [3]

[3] Value includes ORDC price adder

As expected, the ORDC price adder increases in the extreme scenarios due to lower operating reserves. The High Gen Outages and High Load cases result in more frequent scarcity conditions, and this is reflected in the price adder value. Hourly average Operating Reserve Price Adder is presented in Table 2 and the duration curve is shown in Figure 6 for the highest 100 hours of the summer season.

Table 2 – Average Hourly ORDC Adder ($/MWh)

Hour	Base Case	High Gen Outages	Low Wind	High Load
1	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00
12	0.00	0.01	0.00	0.01
13	0.01	2.01	0.00	0.37
14	0.20	13.44	0.68	9.33
15	2.01	20.08	8.45	37.58
16	6.28	43.88	22.34	42.33
17	11.93	45.88	40.65	41.06
18	9.84	53.20	33.54	37.53
19	2.05	14.30	5.85	16.14
20	0.17	1.86	0.12	3.46
21	0.01	0.00	0.01	0.00
22	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00
Average	1.35	8.11	4.65	7.83

Source: LCG UPLAN Simulation

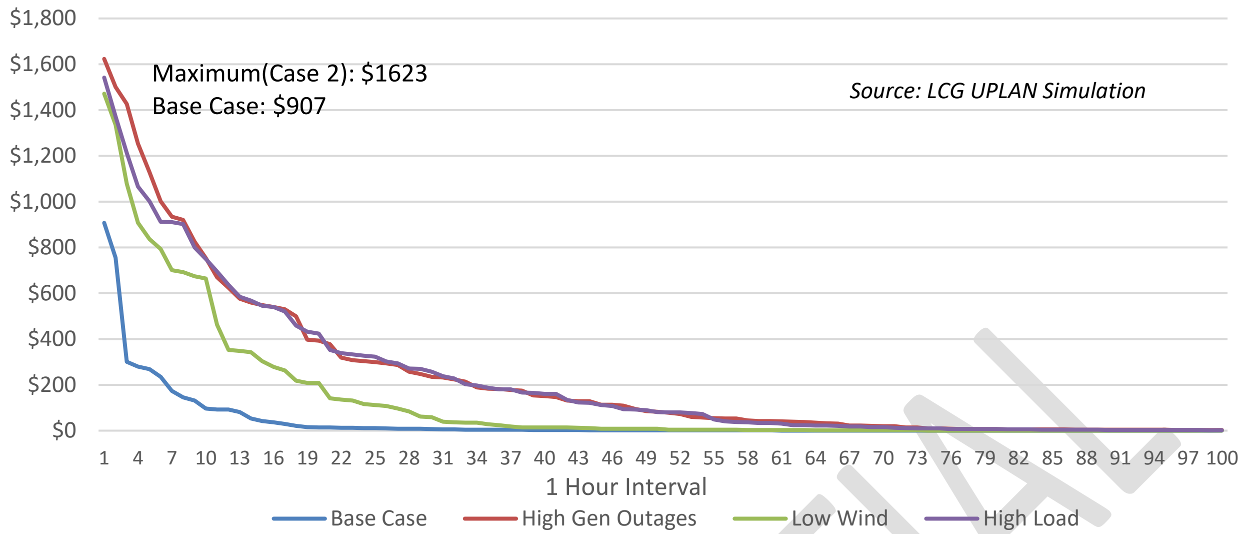


Figure 6 – Operating Reserve Price Adder Duration Curve - Top 100 hours – Summer 2021 ($/MWh)

LCG's simulation indicates that the highest value of the Peaker Net Margin (PNM), which also serves as a simplified measure of the annual net revenue of a peaking unit, corresponds to the High Load scenario. In the Base Case, the cumulative PNM value (June through September) is $32,417. During the same period, the margin is $184,910 in the High Gen Outages case, $80,722 in the Low Wind case and $198,625 in the High Load case. Simulation results show that Peaker's gain the most in August (Figure 7).

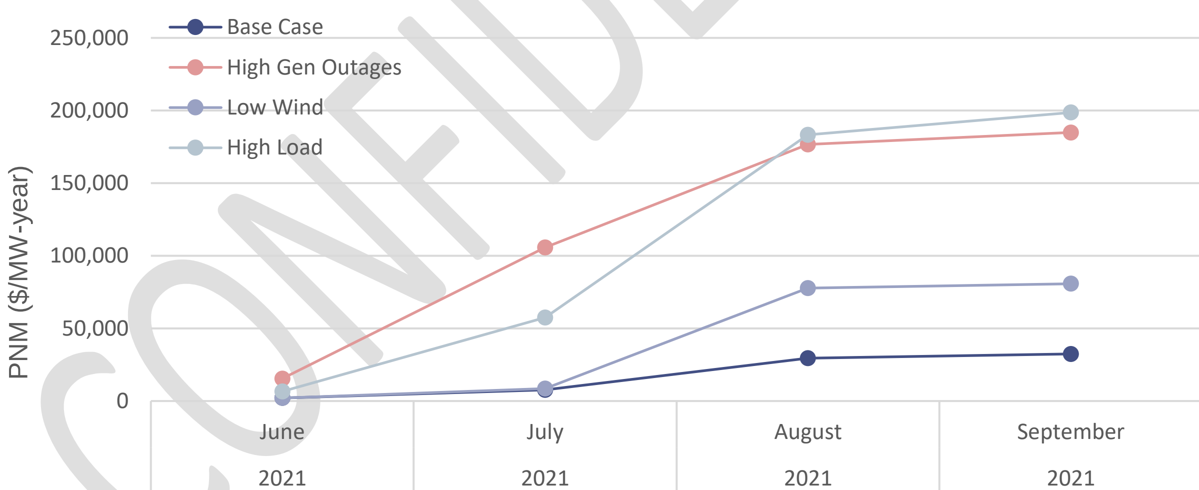


Figure 7 – ERCOT-wide Cumulative Peaker Net Margin

3.2 Generation

Natural gas is dominant in the ERCOT generation mix. The four scenarios see a similar fuel mix, with natural gas accounting for more than 53% of generation. In the Low wind case an increase in natural gas (1%) compensates the reduction in wind production (2%). The high load scenario sees the largest increase in natural gas (6%) and coal generation (4%). Generation by fuel type for all scenarios are given below in Figure 8.

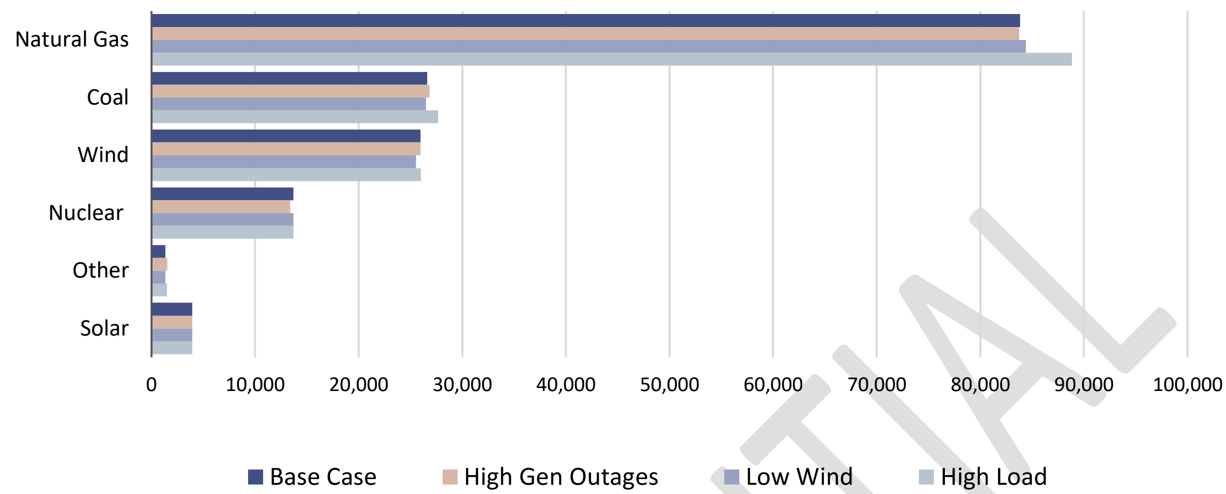


Figure 8 – Generation (GWh) by Fuel and Fuel Mix by Scenario – Summer 2021

3.3 Congestion

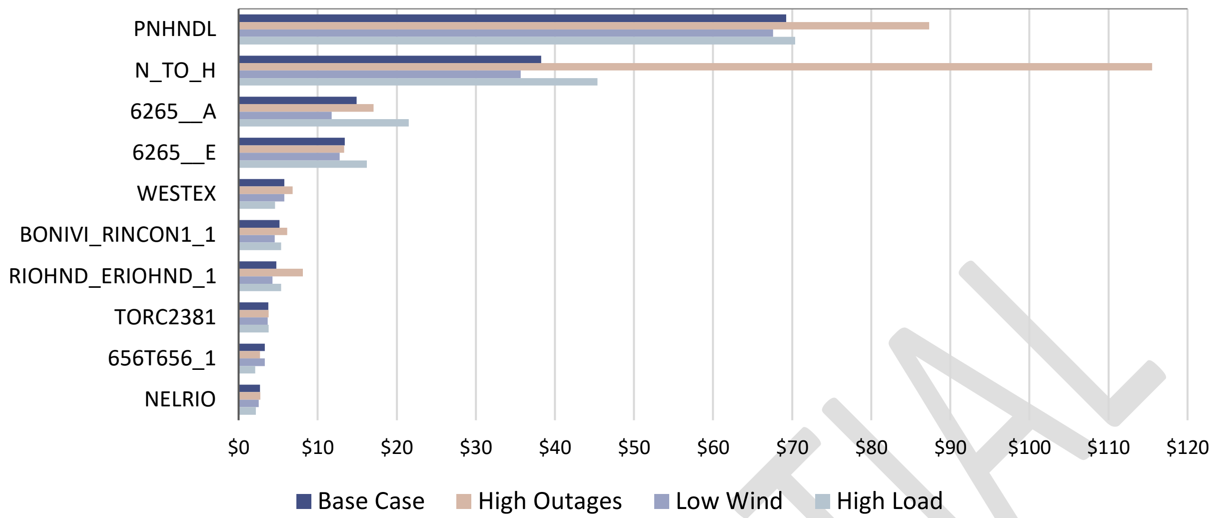
Transmission congestion results vary significantly by scenario. Congestion rents for selected major constraints are shown below in Figure 9. Sensitivity scenarios show that the highest congestion rent values are accrued in the high gen outages and high load scenarios. The Panhandle and North to Houston interfaces are most constrained in the high generation outages case. The North to Houston interface is especially sensitive to high generation outages. The system shortage in the High Gen Outage case and High Load case also caused major congestion in the Houston zone, not seen in the other two cases. Lower wind output in general does not increase congestion compared to the base case.

Table 3– ERCOT Single Line Diagram – Selected Major Constraints [4]

Element	Monitored Element	Line Name	Congestion Rent ($M)			
			Base Case	High Gen Outage	Low Wind	High Load
1	PNHNDL	Panhandle Interface	$69	$87	$68	$70
2	N_TO_H	North to Houston	$38	$116	$36	$45
3	6265__A	Morris Dido to Eagle Mountain SES 138 kV	$15	$17	$12	$21
4	6265__E	Rosen Heights Tap 2 to Deen Switch 138 kV	$13	$13	$13	$16
5	WESTEX	West Texas Export Interface	$6	$7	$6	$5
6	BONIVI_RINCON1_1	Rincon TO Bonnieview 69 kV	$5	$6	$5	$5
7	RIOHND_ERIOHND_1	East Rio Hondo Sub to Rio Hondo 138 kV	$5	$8	$4	$5
8	TORC2381	Torrecillas Transformer 345/34.5 kV	$4	$4	$4	$4
9	656T656_1	Kendall to Bergheim 345 kV	$3	$3	$3	$2
10	NELRIO	Nelson Sharpe – Rio Hondo	$3	$3	$3	$2

Source: LCG UPLAN Simulation

[4] The numbered items in the Element Column of the table refer to elements in Figure 9, based on congestion Rent in millions of dollars.



Source: LCG UPLAN Simulation

Figure 9 – Selected Major Congestion – Summer 2021 Congestion Rent ($M) [5]

4. CONCLUSION

Under expected conditions, the ERCOT region will see sufficient installed generating capacity to serve peak demands during the summer season 2021. Even under the stress of low wind conditions chosen here, this capacity is also sufficient. With the outages chosen in the high outage case, or the demand seen in the High Load case, the tight reserves lead to high pricing and cumulative PNM levels: $184,910 in High Outages case and $198,625 in High Load case, which are comparable to the PNM observed in 2008 and 2011. The study is intended to illustrate the impact of a tight reserve margin rather than to forecast the real-time operation and prices for the summer 2021. The report can be customized to include a vast number of additional details such as individual or grid-scale generator performance, hourly LMPs, transmission congestion, and other information of interest.

Under the scenarios explored, ERCOT sees the most significant boost to prices in the high generation outages and high load cases, where the ORDC price adder contributes to the higher prices due to more frequent occurrence of scarcity conditions. The generation mix fluctuates across these scenarios. The change in the generation mix is the least significant in the high gen outages case. The low wind and the high load scenarios both reflect increases in natural gas and coal production to compensate for the decrease in wind generation and for the increase in load level. Strained conditions have important localized effects, as the sensitivity scenarios have shown significant impact on system transmission constraints, which correspondingly affect the prices. Among scenarios investigated, the high gen outage case experiences the highest congestion.

[5] The numbered items on x-axis map refer to the elements given in Figure 9.